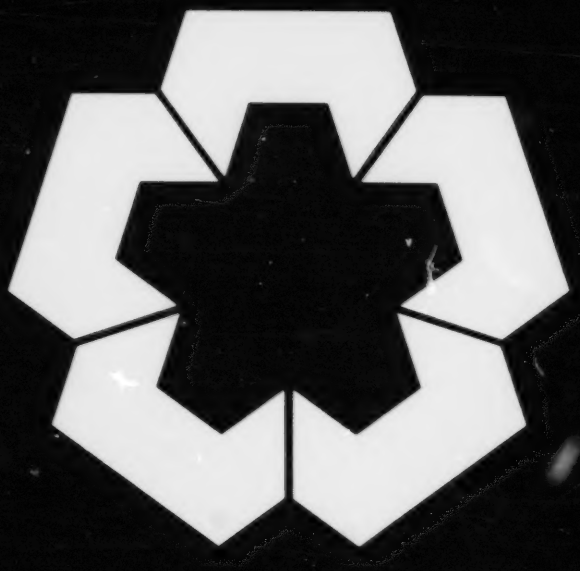

Alberta Sulphur Dioxide Emissions Forecast 1980 to 2000

RMD Report 82/16

Alberta
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ALBERTA SULPHUR DIOXIDE EMISSIONS FORECAST

1980-2000

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ALBERTA SULPHUR DIOXIDE EMISSIONS FORECAST

1980-2000

by

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Western Research
Division of Bow Valley Resource Services Ltd.

for

Research Management Division
Alberta Environment

RMD 82/16

October 1982

This report is made available as a public service. The Department of Environment neither approves nor disagrees with the conclusions expressed herein, which are the responsibility of the authors.

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GUIDE TO SYMBOLS

PJ	petajoule (10^{15} joules)
EJ	exajoule (10^{18} joules)
PJ/a	petajoule per annum
m^3	cubic metre
m^3/d	cubic metre per day
kg	kilogram (10^3 grams)
kg/m^3	kilogram per cubic metre
t	tonne (10^3 kilograms)
kt	kilotonne (10^3 tonnes)
kt/a	kilotonne per annum
t/a	tonne per annum
$t/10^6m^3$	tonne per 10^6 cubic metre
MW	megawatt (10^6 watts)
GW	gigawatt (10^9 watts)
GWh	gigawatt hour
J/kg	joule per kilogram
ng	nanogram (10^{-9} gram)
ng/J	nanogram per joule
kg/t	kilogram per tonne
t/d	tonne per day

ABSTRACT

Sulphur dioxide emissions from Alberta sources are analysed and, based on two projected provincial growth scenarios, forecasts of emissions to the year 2000 are presented.

The growth scenarios developed consider natural gas and conventional crude production, oil sands development, electric energy generation, and other small industry groups such as pulp and paper, fertilizer, refineries, and small manufacturing operations. The high growth scenario is reasonably optimistic for all industry sectors over the forecast period and Alberta's population is forecast to be 3.8 million by 2000. For the low growth scenario, limited growth is projected and Alberta's population is forecast to be 3.0 million by 2000. The reduced industrial and residential growth forecasts lead to reduced electric energy requirements.

After the two growth scenarios are developed, each industry is examined to determine its potential to emit sulphur dioxide to the atmosphere. With the application of present, best practicable and best available technology for either sulphur recovery or sulphur dioxide emission control, the sulphur dioxide emission for each industry group and for the entire province is forecast.

For both growth scenarios, an emission peak is predicted in 1985-86 regardless of the level of technology applied, and, with the application of best practicable technology, a decrease in emissions of from 10 to 30 percent is forecast by the year 2000. The application of present technology over the forecast period would result in an increase in emissions of from 5 to 25 percent, while the use of best available technology would offer a reduction of up to 75 percent.

The sensitivity of the forecast to various industry growth and emission potential assumptions is also examined.

ACKNOWLEDGEMENTS

Western Research would like to thank Alberta Environment for the opportunity to conduct this study, and for the assistance of various staff members in providing historical data and in critically reviewing the document. In addition, the consultation time made available to us by Energy Resources Conservation Board, Electric Utility Planning Council and Economic Development staff members, as well as various company and association spokesmen, is acknowledged.

Special thanks to Dr. H.S. Sandhu for his assistance on behalf of the Research Management Division of Alberta Environment and to senior staff at Western Research for their critical reviews and recommendations.

1. EXECUTIVE SUMMARY

This report presents a detailed analysis of the sulphur dioxide emission potential for Alberta. It provides a basis for monitoring actual industrial development and actual emissions, and for updating the forecast so that emission management strategies can be reviewed and, if appropriate, modified.

The heart of the study is a forecast of two industrial development scenarios. Scenario A represents an optimistic or high-growth outlook that we believe can be realistically achieved by the year 2000. Scenario B represents a more conservative outlook that reflects, in part, the consequences of a society that becomes considerably more conserving of energy and material goods. This scenario also predicts the current recession will be followed by a slow but gradual economic recovery period.

Based on these two forecasts, the potential for sulphur dioxide emissions from Alberta sources is examined and, from this, emission forecasts are presented. The forecasts consider the application of present, best practicable, and best available technology to either the recovery of sulphur as a product or the control of sulphur dioxide emissions.

Finally, the report presents a consolidated sulphur dioxide emission forecast for the province and a sensitivity analysis. From this, recommendations respecting management strategies and monitoring of key indicators are presented for consideration.

1.1 INDUSTRIAL GROWTH PROFILE

In this section of the report, all major sectors of the Alberta economy that may emit sulphur dioxide are examined. These include:

1. Natural gas production;
2. oil sands development;
3. other industries such as conventional crude oil, fertilizer, pulp and paper, refineries, and other operations that are small emitters of sulphur dioxide;

4. electric power generation.

In order to prepare our forecasts, direct reference was made to Energy Resource Conservation Board, National Energy Board and Electric Utility Planning Council documents that deal with energy demands over the forecast period. In addition, industrial activity respecting current and future development projects was assessed and, where appropriate, contacts were made with industry and government personnel. Finally, the forecasts were briefly reviewed with several government and industry representatives.

The two growth scenarios are summarized below.

1.1.1 Scenario A

1.1.1.1 Natural Gas. A demand forecast for marketable gas is developed that includes an annual average increase of 3.7 percent in Alberta, an annual average increase in demand in other provinces of 2.5 percent, expanded eastern Canadian demand equivalent to 450 PJ/a by 2000 to be served by the Trans Quebec and Maritime pipeline, the return to maximum licenced export levels for shipments to the USA, and expanded export licence shipments to the USA equivalent to approximately 7.4 EJ at an initial rate of about 385 PJ/a.

1.1.1.2 Oil Sands. This is perhaps the most controversial aspect of the forecast and one with a significant potential to impact the emissions forecast. The optimistic growth forecast assumes no specific large plant coming on stream, but does consider an increase in production capacity starting in 1990 and totalling 50 000 m^3/d after 10 years. Thus, total capacity would be 84 000 m^3/d by 2000. This growth allows for a Syncrude expansion, several small in situ plants and a plant such as the Shell Peace Project.

1.1.1.3 Other Industries. Scenario A includes modest increases in fertilizer, pulp and paper, and refinery operations over the forecast

period but also reflects the current recession and low demand for commodities provided by these industries. For conventional crude oil, a supply capability forecast is developed.

1.1.1.4 Electric Power Generation. The above industrial growth profile, coupled with a population increase to 3.8 million by 2000, provides the basis for preparing the electric energy requirements forecast. Total requirements of electric energy in 2000 are expected to be 3 times 1980 requirements.

1.1.2 Scenario B

1.1.2.1 Natural Gas. Again a demand forecast is developed for marketable gas that assumes an increase in Alberta's demand of 3.7 percent annually and an increase in demand in other provinces of 2.5 percent annually. Exports to the USA are forecast to remain at the present licenced levels. Expanded eastern Canadian markets and expanded exports to the USA are not forecast.

1.1.2.2 Oil Sands. This scenario assumes no additional oil sands production over the entire forecast period. The existing Suncor and Syncrude plants are expected to be producing at maximum capacity.

1.1.2.3 Other Industries. Scenario B assumes no increases in fertilizer capacity, one new pulp and paper mill, and one small increase in refinery capacity by the year 2000. The Scenario A supply capability forecast for conventional crude oil is adopted for Scenario B.

1.1.2.4 Electric Power Generation. The above forecast of reduced industrial growth, combined with an anticipated population increase to 3 million people by 2000, is used to develop the electric energy requirements forecast. Total electric energy requirements by 2000 are forecast to be 2.4 times 1980 requirements. This corresponds to a growth 20 percent less than Scenario A.

The two growth scenarios span a range that covers profiles of reasonable pessimistic and reasonable optimistic outlooks for growth. They do not span the worst case or the most optimistic case for growth in Alberta.

1.2 SULPHUR DIOXIDE EMISSIONS FORECAST

Each potential emitter of sulphur dioxide is examined in detail, and a forecast of potential emission is established using present technology, best practicable technology and best available technology. Applicable technology includes the sulphur recovery systems used in sour gas processing, and the sulphur dioxide emission control systems used in most other industries where waste gases containing relatively low concentrations of sulphur dioxide are discharged to the atmosphere.

In our analysis, present technology is considered to be standard practice currently adopted extensively by the respective industries to achieve the best results having regard to economics, process control, resource conservation and current environmental regulations and guidelines.

Best practicable technology is considered to be proven technology but not necessarily current standard practice. It may be adopted by the respective industries to meet anticipated environmental regulations and guidelines without a significant adverse impact on economic feasibility, process control or resource conservation.

Best available technology is considered to be technology that is usually only applied by the respective industries to meet specific emission requirements after direct government intervention, without regard to economic considerations. In most cases, it is a developing or emerging technology that is capital- and energy-intensive, and may not have been applied previously in Alberta.

The result of this analysis is the Alberta Sulphur Dioxide Emissions Forecast 1982-2000 shown in Figure 1. Historical data for the years 1974 to 1981 are also plotted for comparison purposes.

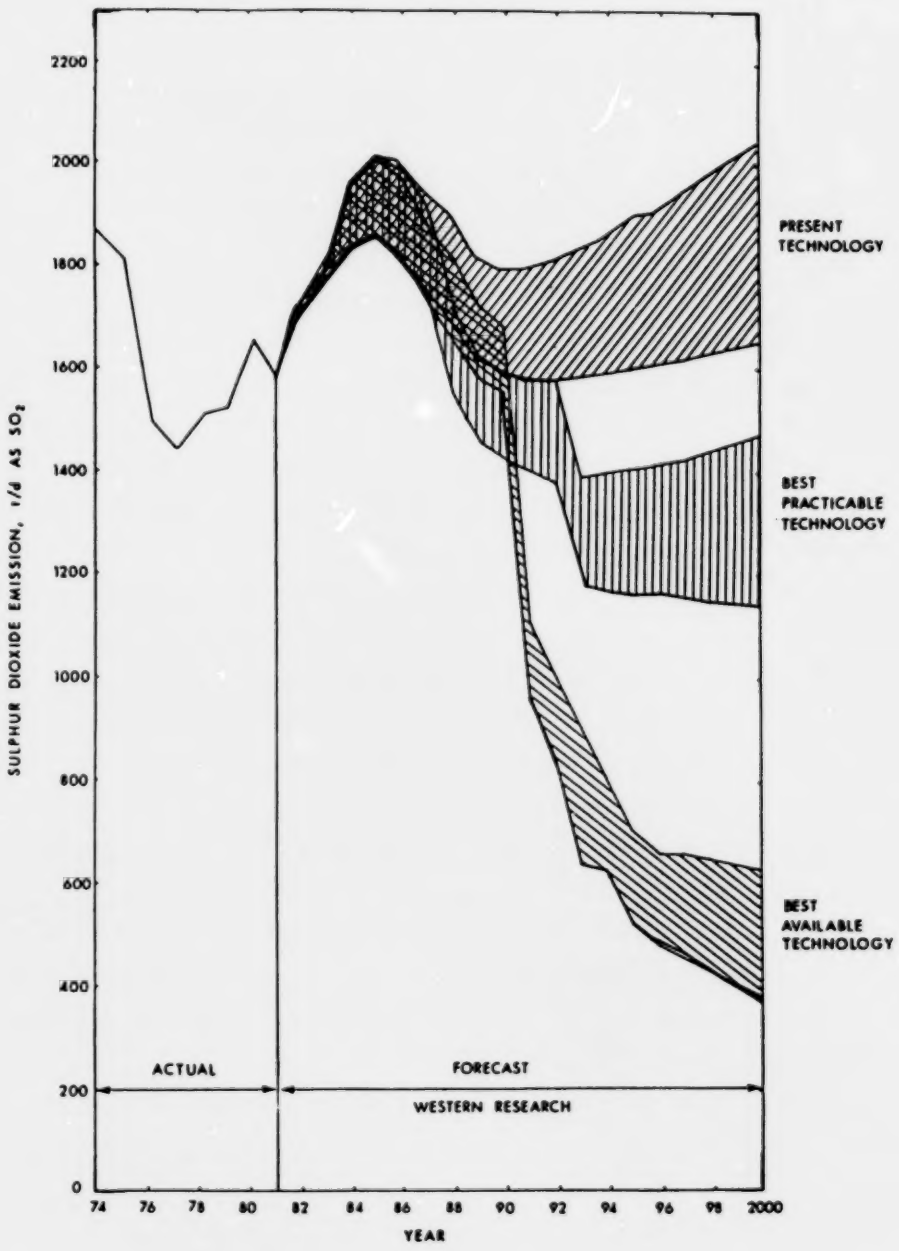

Figure 1. Sulphur dioxide emissions forecast 1980 - 2000.

The following observations are made:

1. Regardless of which growth scenario is achieved or the technology applied for emission control, a modest increase in sulphur dioxide emissions is forecast for the near future (up to about 1988).
2. For both growth scenarios, projected emissions of sulphur dioxide will probably exceed present levels during the entire forecast period if present technology is used for sulphur recovery and emission control.
3. The application of best practicable technology will most likely result in a decreases in sulphur dioxide emissions by 2000 as compared to present emission levels.
4. Substantial reductions in emissions to approximately one third of present levels would be achieved by the application of best available technology.
5. The forecast is somewhat insensitive to the positive impact of improved technology until after 1987-1988. This is due to the time required to modify regulatory requirements, and design and construct the various recovery or control systems. It also recognizes the continued operation of existing systems.

A comparative analysis of the forecast for 1980 and 2000 is presented in Figure 2.

With the application of present technology it is clear that by 2000 the two largest contributors to Alberta's total sulphur dioxide emissions would be coal-fired electric power plants and oil sands plants. As better technology is applied, these two industries also offer the largest potential reductions. The natural gas industry and other industries offer a limited potential for substantially reducing future emissions.

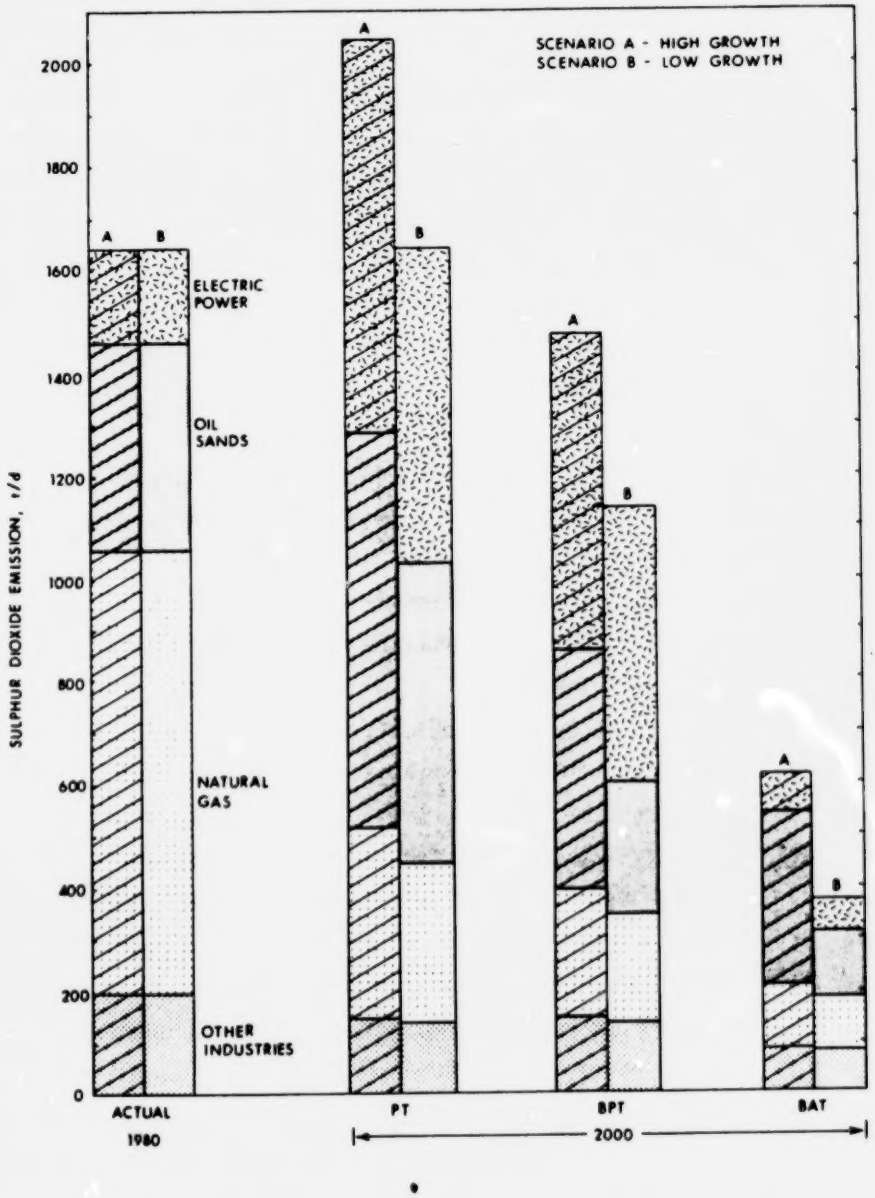

Figure 2. Sulphur dioxide emissions for 1980 and 2000.

Examination of the components of the forecast, and the assumptions made, indicate that a higher emission forecast may result if either of the following occur:

1. The present high production ratio of sulphur to marketable gas is maintained over the forecast period and particularly over the next few years when the highest deliveries of gas are expected.
2. Future oil sands plants do not meet the current Alberta Environment guideline of 3.15 tonnes of sulphur dioxide per thousand cubic metres of bitumen to upgrading.

In a similar way, certain developments may have significant favourable impacts on the emission forecast. The primary development concerns the supply of electric energy requirements. Both scenarios assume the maximum use of coal-fired power plants to supply the energy, but two potential developments would have favourable results.

1. The major hydro project recently announced by the government would significantly alter the emission forecast starting in 1991. By 2000, emissions from the electric energy sector would be about 12 to 15 percent lower than with the all-coal development scenario.
2. Current proposals to recover carbon dioxide from existing or future coal-fired power plant waste gases for enhanced oil recovery projects would have a positive impact on sulphur dioxide emissions. Recovery of carbon dioxide also results in the removal of sulphur dioxide from the flue gas. The potential reduction of sulphur dioxide emissions, should carbon dioxide recovery projects proceed, would be about 150 to 300 t/d, or about one third of the total electric power industry emission forecast for 2000.

1.3 SUMMARY AND RECOMMENDATIONS

The application of best practicable technology to sulphur recovery and sulphur dioxide emission control over the forecast period should result in a modest reduction in total emissions by 2000 as compared to present emission levels.

To better understand the potential for sulphur dioxide emissions from the gas processing industry it is recommended that:

1. The production ratio of sulphur to marketable gas be more fully analysed and methodology be developed to constantly update the forecast production ratio. This is necessary to determine the most appropriate management strategy for the sour gas industry.
2. The development of presently unconnected (not connected to production facilities) reserves of high hydrogen sulphide content natural gas should be considered separately from "conventional" sour gas production. A management strategy should be developed that would ensure minimal emission from these sources.

Present technology for control of sulphur dioxide emissions from oil sands plants does not sufficiently lower the major emissions of existing operations. Only through the application of best practicable technology will reductions be achieved that will assist in ensuring that Alberta's total emissions in 2000 are less than current levels. A management strategy should therefore be developed to reduce present emissions by approximately 60 percent (this would be equivalent to about 5.8 tonnes of sulphur dioxide per thousand cubic metres of bitumen to upgrading averaged for both existing plants).

Electric energy supplied by future coal-fired power plants will achieve the emission objective of 258 nanograms of sulphur dioxide per joule of energy input through the application of coal blending or coal cleaning technology, or flue gas desulphurization

technology. Where flue gas desulphurization technology is applied, there exists a potential to achieve emission levels significantly below the new guideline level. Consequently, there may be considerable opportunity to implement a novel management strategy that considers province-wide or regional emissions from the electric power industry and, at the same time, minimizes the increased cost to the consumer for electricity.

Finally, the limits of these, or of any forecast for that matter, are recognized and it is strongly recommended that both the industrial and the emission forecasts be updated at regular intervals. It would appear that updates every four to five years would normally be appropriate but, because of the potential changes in marketable gas shipments after the National Energy Board Omnibus Hearing and the present uncertainty respecting oil sands developments, a review in late 1983 or early 1984 is recommended.

2. INTRODUCTION

This study was commissioned by Alberta Environment Research Management Division with the objective of establishing a forecast of sulphur dioxide emissions to the year 2000. The study was to examine various industrial growth scenarios, and, in particular, attempt to interpret the impact of the last two years on the future growth of Alberta. Following the development of the growth scenarios, potential emissions of sulphur dioxide were to be estimated using present technology, best practicable technology and best available technology for sulphur recovery and sulphur dioxide emission control.

These objectives are summarized as follows:

1. Develop two industrial growth scenarios, in consultation with Alberta Environment, for the industries emitting SO_2 up to the year 2000.
2. Estimate SO_2 emissions to the year 2000, considering the present technology employed by industry for pollution abatement for the two growth scenarios.
3. Estimate SO_2 emissions to the year 2000 considering the best practicable technology for pollution abatement for the two growth scenarios.
4. Estimate SO_2 emissions to the year 2000 considering the best available technology for pollution abatement for the two growth scenarios.
5. Develop emission control options to maintain a zero growth of SO_2 emissions to the year 2000.

In conducting the study, Western Research has made contact with various industry and government personnel and made extensive use of recent reports regarding industrial development potential in Alberta. Recognizing the difficulty of making forecasts during a time of transition, we have nonetheless completed what we believe to be a realistic forecast of industrial growth and sulphur dioxide emissions.

3. INDUSTRIAL GROWTH FORECAST

This forecast analyses potential industrial growth of the Alberta economy until 2000 and the associated electrical energy generating capacity that will be required to supply the province's needs. Industrial growth will respond to national and international influences which cannot be predicted with complete accuracy. Electric energy generating capacity responds indirectly to these influences and follows actual growth associated with industrial, commercial and residential demands.

Recent predictions of industrial growth in Canada, and particularly in Alberta, may be found in the 1981 report by the National Energy Board (NEB) entitled Canadian Energy Supply and Demand 1980-2000, the Electric Utility Planning Council (EUPC) 1981 forecast of Alberta Energy and Energy Resource Requirements, and other documents not directly referenced. In 1978, Webber and Warne of the Alberta Energy Resources Conservation Board (ERCB) presented energy industry growth projections for Alberta (Alberta Oil and Gas Industry, Annual Statistics, as at December 1981). These documents and others, including recent trade journals and newspapers, have been reviewed and discussions have been held with the ERCB, Environment and Economic Development staff members, EUPC representatives and industry to obtain information for preparing this forecast. These reviews and discussions have been directed towards establishing a best estimate of industrial growth.

Analysis of industrial development in Alberta during the forecast period has provided the basis for two growth scenarios. They are described in the following sections and referred to as Scenario A and Scenario B. Scenario A generally represents the more optimistic outlook that prevailed in 1980-81 and may yet be realized by 2000. Scenario B represents a more conservative outlook that reflects current economic and political factors, as well as general trends in energy conservation. It is believed that energy conservation may be a more important factor in the current economic situation than is generally accepted.

During the period over which this study was conducted, significant changes in the marketplace and in government policies have taken place. Attempts have been made to address these recent developments but it is recognized that a detailed analysis of each sector of the Alberta economy is outside the scope of the project.

3.1 NATURAL GAS

Alberta natural gas production supplies three major market sectors - Alberta, other provinces, and the United States. To develop the growth profile of the natural gas industry in Alberta, these three market sectors are examined.

3.1.1 Alberta Requirements

In Alberta, the petrochemical industry plays a significant role in the growth of natural gas requirements and will continue to do so during the forecast period; hence, it is treated separately. The forecast of petrochemical natural gas requirements in the 1981 EUPC report is adopted as the basis of this forecast, with the following adjustments made to reflect the current development situation of the industry in Alberta:

1. Growth of the ethylene and derivative plants, and the ammonia sector natural gas requirements is delayed three years to reflect the current soft economic conditions.
2. Growth of the methanol sector natural gas requirements is advanced three years to reflect the proposed construction of a world-scale methanol plant east of Edmonton. Full production is anticipated by 1986. No additional methanol plants are expected in the forecast period.

A listing of the potential petrochemical projects on which the EUPC forecast is based is summarized in Appendix A.

With these adjustments, the petrochemical natural gas requirement is forecast to grow from 147 PJ/a in 1980 to 372 PJ/a in 2000.

Natural gas requirements from the residential, commercial and industrial sectors (excluding petrochemicals) in Alberta are expected to grow from 357 PJ/a in 1980 to 678 PJ/a in 2000. This is an average annual growth rate of 3.2 percent. Historical data for the total indigenous deliveries of natural gas in Alberta are obtained from the ERCB Oil and Gas Industry, Annual Statistics (1982).

Total Alberta requirements for natural gas is the sum of the petrochemical requirements and the requirements from the other sectors. This is outlined in Table 1. The total Alberta requirement was 504 PJ/a in 1980 and is expected to be 1050 PJ/a in 2000, representing an average annual growth rate of 3.7 percent. This forecast has been used for both growth scenarios and may be 10 to 20 percent high for Scenario B. However this would have a minor impact on the total gas requirements and on the electric energy requirements of the gas industry.

3.1.2 Deliveries to Other Provinces

Data regarding the past delivery of Alberta gas to the other provinces are obtained from the ERCB annual statistics reports for the oil and gas industry (1982). This amount was 956 PJ/a in 1980 and is expected to grow to 1591 PJ/a in 2000 at an average annual growth rate of 2.5 percent.

It should be noted that this forecast does not include the expanded eastern markets (i.e., east of Montreal and the Maritimes) that would be served by the proposed Trans Quebec and Maritime (TQM) Pipeline. At this time, it is uncertain whether Alberta gas or offshore, east coast, gas will supply the expanded eastern markets; hence, these requirements are treated separately in the forecast.

The expanded eastern market requirements are outlined by the previously-noted NEB report (1981). According to the report, the combined requirements of the Quebec and Maritimes markets are expected to grow to 451 PJ/a in 2000.

Table 1. Alberta's indigenous requirements.

Year	Petrochemical Requirements PJ/a	Other Sector Requirements PJ/a	Total Requirements PJ/a
1980	147	357	504
1981	147	369	516
1982	163	382	545
1983	187	395	582
1984	220	409	629
1985	228	423	651
1986	262	437	689
1987	285	452	737
1988	310	467	777
1989	324	482	806
1990	318	497	815
1991	318	513	831
1992	328	530	858
1993	335	548	883
1994	342	564	906
1995	346	582	928
1996	353	601	854
1997	363	620	983
1998	365	638	1 003
1999	368	658	1 026
2000	372	678	1 050

Two forecasts are made for the requirements of Alberta gas from the other provinces - one without the expanded eastern markets, the other including the expanded eastern markets to be served by the TQM pipeline. Both forecasts are summarized in Table 2.

3.1.3 Exports to the United States

During 1981, approximately half of the authorized gas export of 1330 PJ was actually exported. This was due mainly to strong price competition, an over-supply of natural gas in the United States, and, in part, incomplete transportation facilities for some newly-licenced exports. This situation is expected to improve significantly by 1985. As a result, Alberta gas exports are expected to remain relatively flat from 1981-83, and then increase rapidly to a peak of 1200 PJ/a in 1986 to reflect the expected demand from the United States.

Historical delivery data of Alberta gas exports to the United States were obtained from the ERCB annual statistics report (1982). Authorized export data of Alberta gas were obtained from the 1981 NEB Report.

It should be noted that the NEB is in the process of Phase II of their Omnibus Hearing to consider some 30 applications for additional gas export. In Phase I of the Omnibus Hearing, the NEB has already adopted a more flexible approach in determining surplus natural gas (NEB 1982). At the conclusion of Phase III of the hearing in 1983, the NEB may grant additional gas export licenses. For the purpose of this forecast, an exportable surplus of 7.4 EJ is assumed and a deliverability profile for this surplus is based on an initial rate of take of 1:7000 for a flat life of eight years with production declining thereafter at 8.22 percent per year.

Table 3 presents a summary of Alberta exports to the United States, including authorized export volumes and expected delivery volumes, estimated additional export volumes (based on 7.4 EJ surplus) and the total expected export volumes for the forecast period.

Table 2. Requirements from other provinces.

Year	Traditional Other Provinces' Requirements PJ/a	New Quebec & Maritime Requirements PJ/a	New Expanded Requirements PJ/a
1980	956	-	956
1981	995	-	995
1982	1 020	-	1 020
1983	1 045	-	1 045
1984	1 072	-	1 072
1985	1 098	220	1 318
1986	1 126	245	1 371
1987	1 154	270	1 424
1988	1 183	295	1 478
1989	1 212	320	1 532
1990	1 243	345	1 588
1991	1 274	355	1 629
1992	1 306	365	1 671
1993	1 338	375	1 713
1994	1 372	385	1 757
1995	1 406	395	1 801
1996	1 441	406	1 847
1997	1 477	417	1 294
1998	1 514	428	1 942
1999	1 552	439	1 991
2000	1 591	451	2 042

Table 3. United States' export requirements.

Year	Authorized Exports (Existing Licences) PJ/a	Estimated Exports (Existing Licences) PJ/a	Additional Exports (New Licences) PJ/a	Total Expected Exports (New & Existing Licences) PJ/a
1980	983	749	-	749
1981	1 331	715	-	715
1982	1 519	787	-	787
1983	1 501	900	-	900
1984	1 498	1 123	385	1 508
1985	1 402	1 192	385	1 577
1986	1 213	1 206	385	1 591
1987	984	984	385	1 369
1988	771	771	385	1 156
1989	368	368	385	752
1990	244	244	385	629
1991	145	145	385	530
1992	62	62	353	447
1993	54	54	323	439
1994	14	14	298	399
1995	11	11	273	397
1996	0	0	251	251
1997	0	0	230	230
1998	0	0	211	211
1999	0	0	194	194
2000	0	0	176	176

3.1.4 Total Alberta Gas Requirements

At this time, it is uncertain whether new export licenses will be granted by the NEB at the conclusion of the Omnibus Hearing. In addition, considerations are now being given to supply the Quebec and Maritimes markets with offshore, east coast gas instead of Alberta gas.

To accommodate these uncertainties in forecasting, four cases were developed for assessing potential Alberta marketable gas production. These cases are described as:

Case 1. Alberta requirements, plus exports under existing licenses, plus requirements from other provinces without expanded Quebec and Maritimes markets.

Case 2. Alberta requirements, plus exports under existing licenses, plus requirements from other provinces with expanded Quebec and Maritimes markets.

Case 3. Alberta requirements, plus exports under existing and new licenses, plus requirements from other provinces (without expanded Quebec and Maritimes markets).

Case 4. Alberta requirements, plus exports under existing and new licenses, plus requirements from other provinces plus expanded Quebec and Maritimes markets.

The four cases are summarized in Table 4. Figure 3 outlines the four growth profiles in graphical form.

As can be observed from Figure 3, Case 4 provides the highest forecast, while Case 1 provides the lowest forecast. Generally, these forecasts project that the marketable gas production in Alberta will increase slightly between 1980-83 and rapidly increase as export demand increases to a peak in 1986. Production is expected to decline between 1986-92 as exports diminish and then increase again after 1992 as Canadian domestic demands increase. In the lowest forecast (Case 1), Alberta marketable gas production by

Table 4. Total Alberta marketable gas deliveries.

Year	Scenario B Case 1 PJ/a	Case 2 PJ/a	Case 3 PJ/a	Scenario A Case 4 PJ/a
1980	2 209	2 209	2 209	2 209
1981	2 226	2 226	2 226	2 226
1982	2 352	2 352	2 352	2 352
1983	2 527	2 527	2 527	2 527
1984	2 824	2 824	3 209	3 209
1985	2 941	3 161	3 326	3 546
1986	3 031	3 276	3 416	3 661
1987	2 875	3 145	3 260	3 530
1988	2 730	3 025	3 116	3 411
1989	2 386	2 706	2 770	3 090
1990	2 302	2 647	2 687	3 032
1991	2 252	2 605	2 635	2 990
1992	2 226	2 591	2 611	2 976
1993	2 275	2 650	2 660	3 035
1994	2 292	2 677	2 617	3 052
1995	2 348	2 740	2 731	3 126
1996	2 395	2 801	2 646	3 052
1997	2 460	2 877	2 690	3 107
1998	2 517	2 945	2 728	3 156
1999	2 578	3 017	2 772	3 211
2000	2 641	3 092	2 817	3 268

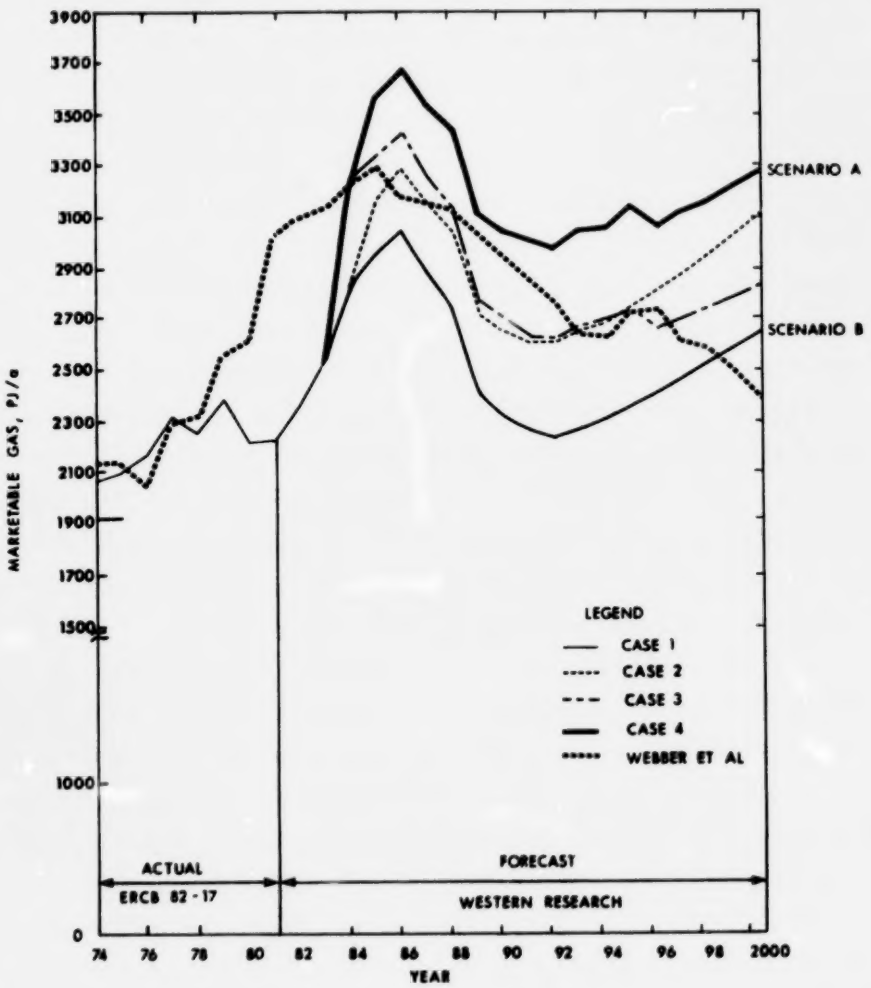

Figure 3. Alberta marketable gas production.

2000 is expected to be 2641 PJ/a, an increase of 20 percent compared with the 1980 production level of 2209 PJ/a. In the highest forecast (Case 4), Alberta marketable gas production is expected to be 3268 PJ/a by 2000, representing a 48 percent increase compared with the 1980 production level.

For the purposes of comparison, the Alberta marketable gas production profile developed by Webber and Warne (1979) is also shown in Figure 3. This forecast is generally higher than the forecasts of cases 1, 2 and 3. The deviations are quite noticeable from 1980-84 and then from 1988-93. The former is due to the current low demand for natural gas. The latter is due to a more gradual drop in export anticipated by Webber and Warne after 1987 as compared with the forecasts of cases 1, 2 and 3.

Case 4 is generally a higher forecast than that of Webber and Warne except during the beginning of the forecast period, i.e., 1980-83. However, it is observed that the cumulative production over the period 1980-2000 for the Webber forecast is almost the same as the cumulative production for the high-case forecast.

It should also be noted that a detailed examination of deliverability is beyond the scope of this study. The productivity of gas reserves in Alberta is assumed to be sufficient to satisfy the demand forecasts of the four cases during the latter years of the forecast period, i.e., 1996-2000.

For the purposes of developing sulphur dioxide emission forecasts in Chapter 4 the highest forecast (Case 4) is taken as Scenario A. The lowest (Case 1) is taken as Scenario B.

3.2 OIL SANDS

Until recently, oil sands mega-projects (mining and in situ) were projected to be a significant part of Canada's strategy to become self-sufficient in oil. However, world oil supply and demand, interest rates, company investment requirements and cash flow from other operations, as well as government policies and programs, were such that in the first half of 1982 the proposed projects of Esso,

Alsands and Canstar were halted. Revival of these projects in the near future does not appear likely based on actions by the various participants to reassign the staff that had been charged with the planning and design of the three projects.

At this time, the economic viability of mega-sized oil sands projects has been seriously questioned by many industry experts and a general feeling persists that small modular-type projects, probably in situ, will proceed rather than the mega-sized ones. In its 1982 growth forecasts, the Electric Utility Planning Council carries several modular-sized projects but no mega-sized oil sands development (Taylor: pers. comm.).

Similarly, Economic Development personnel (Szecheny: pers. comm.) suggested that several in situ modular design plants, each with capacities of about 2000-3000 m^3/d of crude bitumen may proceed over the forecast period. In addition, it is possible that the Shell Peace River project will proceed in the mid 1990s with a capacity of approximately 22 500 m^3/d (Gorrill: pers. comm.).

Two potential development scenarios were considered for subsequent forecasts of sulphur dioxide emissions. The low growth scenario assumes no major mining or in situ projects other than Suncor and Syncrude and various experimental projects.

The high growth scenario assumes that modular plants, the Shell Peace River plant or expansions of existing mining plants would proceed during the 1990s and new capacity would total 50 000 m^3/d by 2000. The forecast capacity buildup of these projects is indicated in Figure 4. The first unit is assumed to be in operation by 1990.

In August of 1982, Suncor announced plans to extend the life of its plant by approximately five years but no increase in maximum design capacity was indicated. This announcement extends Suncor's operation to the end of the forecast period. Syncrude also announced programs that would improve their operation and increase capacity by about 1500 m^3/d. These are considered to be programs to improve the efficiency of the existing plants and not major expansions of capacity.

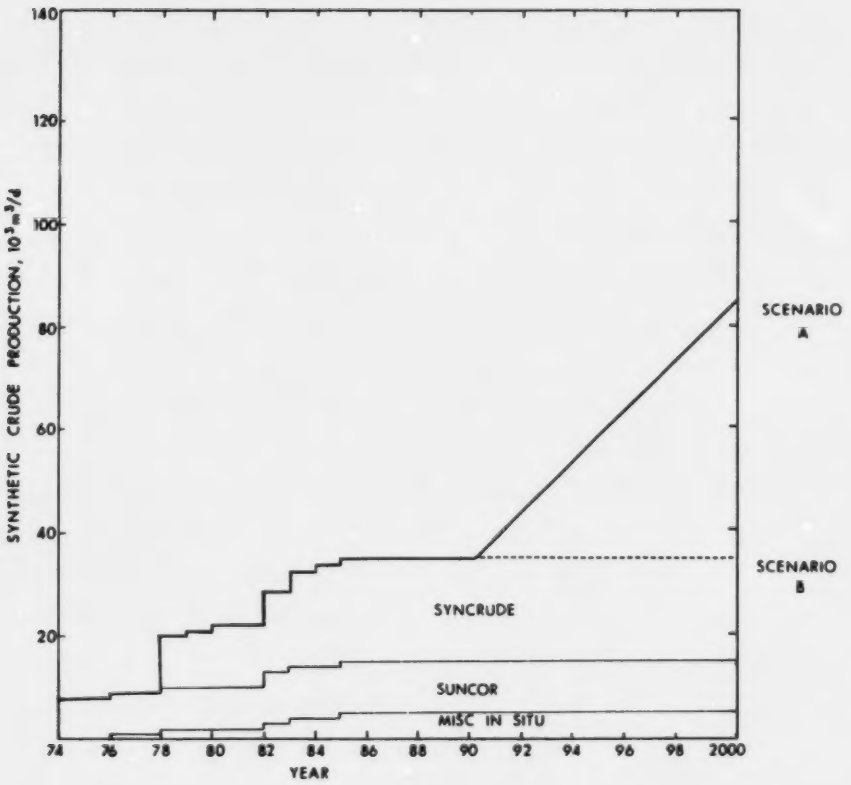

Figure 4. Oil sands production forecast (licenced levels).

3.3 OTHER INDUSTRIES

The many other industries in Alberta have little or no direct impact on sulphur dioxide emissions. Exceptions, of course, are conventional crude oil production, fertilizer, pulp and paper, refineries and sulphur-containing chemical manufacturing operations. These industries are reviewed in the following sections.

3.3.1 Conventional Crude Oil

Conventional crude oil in Alberta can be classified into two types: light and medium crude oil with density of less than 900 kg/m^3, and heavy crude oil with density of 900 kg/m^3 or more.

Light and medium crude oil production in Alberta is declining and this trend is expected to continue throughout the forecast period. Production in 2000 is estimated to be 24 429 x $10^3m^3/a$, about half the 1980 production level of 58 564 x $10^3m^3/a$. As a result of this decline, the demand for Alberta light and medimum crude oil will always exceed total supply capability from established reserves and reserves additions (due to enhanced oil recovery techniques and new discoveries). Hence, production of light and medium crude oil in Alberta is expected to be at full production capacity throughout the forecast period.

Heavy crude oil production in Alberta is expected to remain relatively unchanged throughout the forecast period. Production in 1980 is 4629 x $10^3m^3/a$. At this time, there is limited refining capacity for heavy crude oil in Canada. Demand for heavy crude oil is seasonal and primarily dependent on the asphalt demand. However, as the supply of light and medium crude oil decreases, refiners may replace it with heavy crude oil. Demand for Alberta heavy crude oil is expected to continue and will increase during the forecast period. Production of heavy crude oil in Alberta is forecast to be at full producing capacity from established reserves and reserves additions (due to enhanced oil recovery techniques and new discoveries). It should be noted that this heavy oil production forecast does not include production from experimental oil sands projects.

Table 5 outlines the light and medium crude oil, heavy crude oil and the total conventional crude oil production forecast in Alberta from 1980-2000 (Hart: pers. comm.).

3.3.2 Fertilizer

The fertilizer industry in Alberta is fairly well established, with major operations centred in Medicine Hat, Calgary and Edmonton. Presently, major expansions to produce ammonia and urea are under construction at both Esso Chemical Canada (Redwater) and Sherritt Gordon Mines (Fort Saskatchewan).

Over the forecast period, the addition of two more plants, one in 1990 and one in 1993, of a size comparable to the Esso expansion are assumed for growth Scenario A. This forecast is the same as that used in the EUPC submission to the ERCB in 1981 (1981). For growth Scenario B, no additional plants are forecast until after 2000.

The fertilizer plants are small contributors of potential sulphur dioxide emissions (less than 1.5 percent in 1978) (Alberta Environment 1979).

3.3.3 Pulp and Paper

Alberta Economic Development indicates that several new plants may proceed during the forecast period (Anderson: pers. comm.). This includes a major project associated with the Brazeau Timber Block for which Alberta Lands and Forests received development proposals on June 1, 1982, and the British Columbia Forest Products Ltd. 175 kt/a pulp and paper plant near Whitecourt. For the high growth forecast, the Whitecourt and Brazeau developments are projected to proceed in 1985 and 1995, respectively. For Scenario B, only the Whitecourt project in 1990 is considered.

3.3.4 Refining Capacity

Alberta refining capacity is summarized in Table 6. Capacities for existing plants, current expansions and new plants presently under construction are indicated.

Table 5. Crude oil production forecast.

Year	Light & Medium Crude Oil Production ($10^3m^3/a$)	Heavy Crude Oil Production ($10^3m^3/a$)	Total Conventional Crude Oil Production ($10^3m^3/a$)
1980	58 564	4 629	63 193
1981	52 171	4 807	56 978
1982	51 258	4 740	55 998
1983	50 735	4 745	55 480
1984	46 355	4 745	51 100
1985	43 800	4 745	48 545
1986	40 880	4 380	45 260
1987	39 055	4 380	43 435
1988	36 135	4 380	40 515
1989	35 040	4 380	39 420
1990	33 215	4 380	39 595
1991	31 755	4 380	36 135
1992	30 285	5 110	35 405
1993	29 565	4 745	34 310
1994	28 105	4 380	32 485
1995	27 375	5 110	32 485
1996	26 645	4 745	31 390
1997	26 280	5 110	31 390
1998	25 550	5 110	30 660
1999	25 185	5 110	30 295
2000	24 429	5 110	29 539

Table 6. Alberta's refining capacity.

Company	Capacity m^3/d	Status
Esso Petroleum Canada		
Strathcona	27 500	Expansion-complete 1983
Gulf Canada Products Company		
Calgary	2 051	Existing
Edmonton	19 200	Expansion-complete 1983
Husky Oil Operations Ltd.		
Lloydminster	3 973	Expansion-complete Jan. 1983
Shell Canada Ltd.		
Bowden	795	Existing
Scotford	8 000	New plant-complete 1984
Texaco Canada		
Edmonton	4 450	Expansion-completed 1981
Turbo Resources		
Calgary	4 800	New plant-complete Sept. 1982

Statistics for refiners' net sales to year end 1981 (Oilweek June 14, 1982) show an approximate 1.3 percent annual decline for the prairie region which includes Alberta. A further decline of 1.1 percent is forecast for 1982 (Oilweek June 14, 1982). We believe that this is due mainly to a combined impact of energy conservation, higher prices and the present recession. It is anticipated that the decline in demand will continue throughout 1982 and into 1983.

Considering these factors and the supply and demand forecast presented in the EUPC submission, a revised forecast is suggested. A low growth scenario is projected to include a potential expansion of only 4000 m^3/d in 1993 and no further increases in capacity until after the year 2000. For the high growth scenario, potential expansions of 3200 m^3/d in 1990 and 8000 m^3/d in 1995 are projected.

3.3.5 Other Manufacturing Operations

Presently, this category of manufacturing operations with licences to emit sulphur dioxide includes Alcan in Edmonton and Thio-Petchem in Fort Saskatchewan. No new plants are anticipated during the forecast period and the existing ones are projected to continue operation at their present production levels.

3.4 ELECTRIC UTILITY GROWTH

Indirectly all industrial development may result in potential sulphur dioxide emissions through its requirements for electric power, the majority of which is supplied by coal-fired power plants. In the analysis of electric utility growth all industries are considered.

Alberta electric power requirements from 1981 to 2005 were outlined in a submission to the Energy Resources Conservation Board dated January 1981 by the Electric Utility Planning Council, Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited. In the report the electrical energy and natural gas energy requirements of all sectors of the Alberta economy were addressed.

Table 7 outlines the 1980 and 2000 forecast growth and distribution of electric power requirements of the Alberta Interconnected System (AIS) by sector, as presented in the EUPC submission. Over the twenty-year period a 3.2-fold increase was projected. The 1981 EUPC Submission was used as a base to prepare the present forecast of electric utility growth.

The industrial development scenarios described in sections 3.1 to 3.3, as well as other related factors, were used to establish the present electric utility energy requirement forecast. In addition, revised estimates of residential, commercial, street lighting, farm and transportation were prepared.

For the latter, the major assumptions were:

1. Residential. Scenario A: Alberta's population would be approximately 3.8 million by 2000. This is consistent with the EUPC forecast and similar to the high fertility, high migration scenario (series 8) predicted by Alberta Treasury, Bureau of Statistics (Alberta Bureau of Statistics 1981).
   Scenario B: Alberta's population would be approximately 3.0 million by 2000. This corresponds to the medium fertility, low migration scenario (series 6) predicted by Alberta Treasury (Alberta Bureau of Statistics 1981). The impact of this is a 20 percent reduction in residential demand for electricity when compared to Scenario A.
2. Commercial. Commercial demand was adjusted proportional to the revised population estimates.
3. Street lighting. This demand was adjusted proportional to revised population estimates.
4. Farm. Farm demand was not adjusted and was assumed to be the same for both growth scenarios.
5. Transportation. Demands for crude oil and natural gas pipeline operation, interbasin water transfer and rail

Table 7. AIS energy requirements.[a]

	1980 GW h	2000 GW h
Residential[b]	4 300	10 793
Commercial	6 655	15 600
Street Lighting	283	478
Farm	1 098	2 325
Transportation	595	5 564
Industrial		
o oilfields	1 305	4 387
o gas plants	940	2 921
o natural gas reprocessing	268	1 557
o refineries	374	1 132
o oil sands	98	5 606
o petrochemicals	1 571	4 192
o forest products	147	1 625
o cement	168	769
o coal	425	2 235
o other industrial	1 445	3 491
Total AIS Industrial	6 691	28 515
Losses	2 139	6 644
Alberta Total	21 761	69 919

[a] Source: EUPC. 1981 submission to the Energy Resources Conservation Board, Alberta Energy and Energy Resource Requirements 1981 to 2005.

[b] present population 1980 - 2 132 000
projected population 2000 - 3 802 000

line electrification were adjusted, based in part on the updated industrial growth profiles and on the author's views of the likelihood of certain actions to be taken. They were reviewed with EUPC representatives and considered to be reasonable development possibilities.

A more detailed discussion of the present forecast for electrical requirements is presented in Appendix B.

Table 8 summarizes the total AIS electrical energy requirements as revised for scenarios A and B over the forecast period. Figure 5 also includes data for 1975-81 (ERCB 82-28) and compares the 1981 EUPC estimates with the present revised estimates. By 2000 Scenario A and Scenario B forecasts are, respectively, 10 and 25 percent less than the 1981 EUPC forecast.

The electric energy supplied by coal for the present forecast is calculated using the same assumptions for grid and hydro sources of electric energy as outlined in Case 1 and Case 3 of the 1981 EUPC submission. Case 1 assumes a maximum contribution by coal, while Case 3 assumes that 2000 MW of non-thermal capacity is brought on stream between 1990 and 1995. Although the data presented corresponds to this capacity being sourced by the Western Grid (1000 MW) and an unspecified hydro project (1000 MW), it is most likely that a major hydro project will supply the total capacity.

The results are summarized in Table 9 and Figure 6. Figure 6 includes historical data for 1975 to 1981 (ERCB 82-28).

For both scenarios the maximum use of coal is assumed as the base case and a low-side sulphur dioxide forecast is also examined assuming the substitution of 2000 MW of capacity from a non-thermal source.

Table 8. Total AIS electric energy requirements.

	1980 GW h	1985 GW h	1990 GW h	1995 GW h	2000 GW h
Scenario A					
Non Industrial[a]	12 820	16 974	20 633	25 179	31 457
Industrial[b]	6 785	13 206	16 864	21 343	25 500
Losses at 11%	2 157	3 320	4 125	5 117	6 265
Total Estimate	21 762	33 500	41 622	51 639	63 222
Scenario B					
Non Industrial[a]	12 820	15 925	18 444	21 295	24 713
Industrial[b]	6 785	11 844	15 466	19 094	22 213
Losses at 11%	1 410	3 055	3 730	4 443	5 162
Total Estimate	21 762	30 824	37 640	44 832	52 088

[a] See Appendix B, Table 19
[b] See Appendix B, Table 20

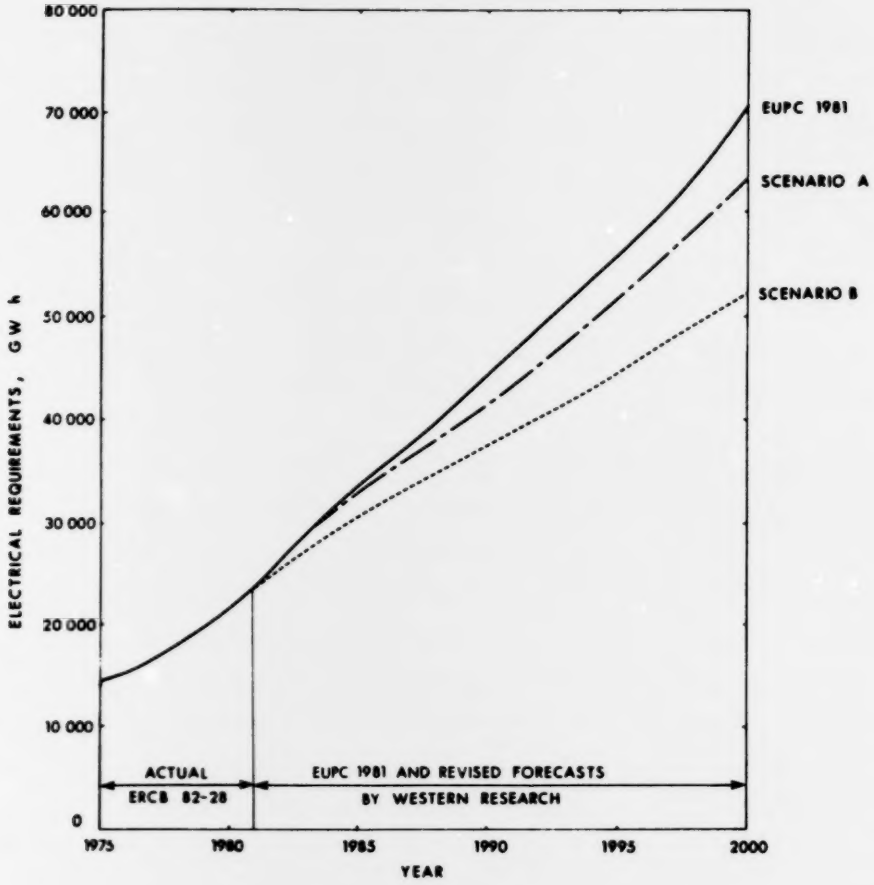

Figure 5. Total AIS electrical requirements.

Table 9. Supply of energy requirements by source type.

	Hydro GW h	Gas GW h	Grid GW h	Revised Total[a] GW h	Coal Portion GW h
Scenario A					
Case 1 - All Coal					
1980 (actual)	1 699	3 728	0	21 762	16 335
1985	1 780	4 380	6	33 500	27 334
1990	1 780	3 724	10	41 622	36 108
1995	1 401	3 547	36	51 639	46 655
2000	1 330	3 833	49	63 222	58 010
Case 2 - Hydro Plus Western Grid					
1980 (actual)	1 699	3 728	0	21 762	16 335
1985	1 780	4 380	6	33 500	27 334
1990	1 780	4 181	50	41 622	35 611
1995	5 715	3 760	4 421	51 639	37 743
2000	5 644	2 364	4 386	63 222	50 828
Scenario B					
Case 1 - All Coal					
1980 (actual)	1 699	3 728	0	21 762	16 335
1985	1 780	4 380	6	30 824	24 658
1990	1 780	3 724	10	37 640	32 126
1995	1 401	3 547	36	44 832	39 848
2000	1 330	3 833	49	52 088	46 876
Case 2 - Hydro Plus Western Grid					
1980 (actual)	1 699	3 728	0	21 762	16 335
1985	1 780	4 380	6	30 824	24 658
1990	1 780	4 181	50	37 640	31 629
1995	5 715	3 760	4 421	44 832	30 936
2000	5 644	2 364	4 386	52 088	39 694

[a] Actual total for 1980 is 21 910. Table 8 estimated total for 1980 is 21 762

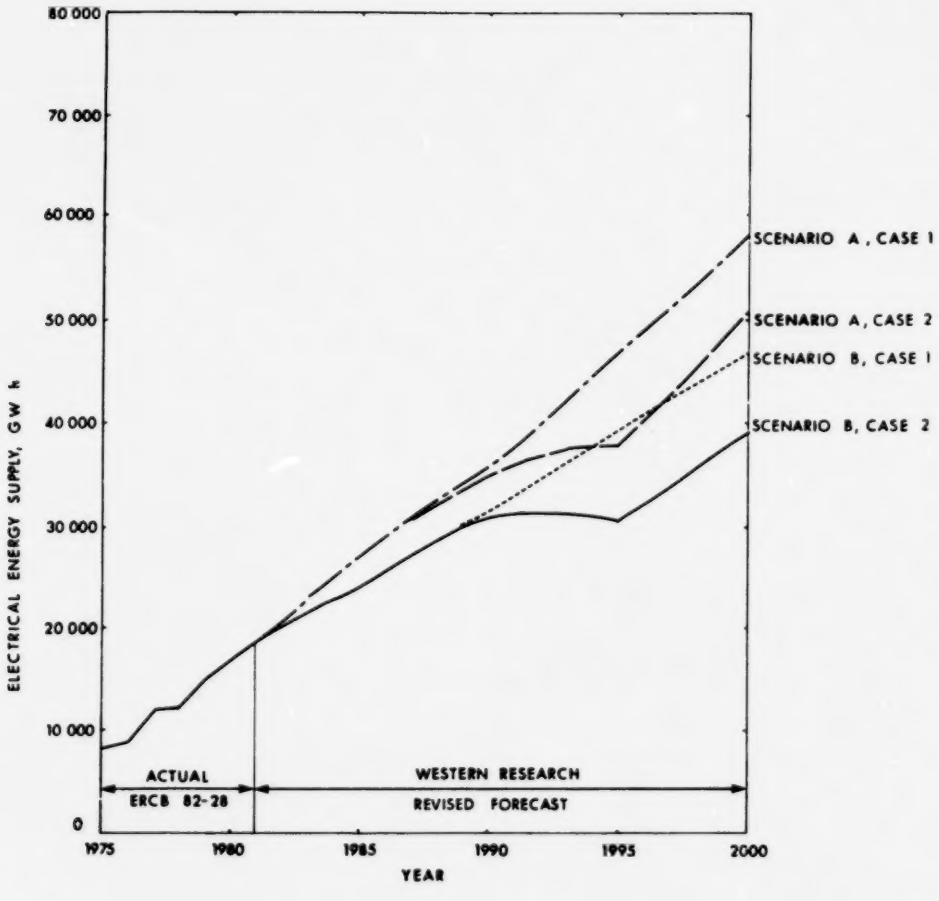

Figure 6. AIS electrical requirements supplied by coal.

4. SULPHUR DIOXIDE EMISSIONS FORECAST

The industrial, commercial and residential growth forecast in Section 3 provides the basis for predicting potential sulphur dioxide emissions. In all cases, sulphur enters the system in a form other than sulphur dioxide and, through the process of upgrading the resource or generating energy, an uncontrolled sulphur dioxide emission results. With some of these operations substantial quantities of elemental sulphur are produced as product, and in others conditions are such that no sulphur is presently recovered.

The need for sulphur recovery has been, and to a large extent still is, determined by an industry and government assessment of need. In some cases, the need is not questioned because the large quantities of sulphur may be economically recovered, but the degree of recovery is debated.

In this section each industry is examined to establish its sulphur emission potential over the forecast period, and then sulphur recovery or emission control technology is applied to determine the forecast emission. Three classes of technology have been adopted and are briefly described in terms of their philosophy.

1. Present Technology. Present Technology (PT) represents the current industry standard or the current regulatory guideline for recovery or control.
2. Best Practicable Technology. Best Practicable Technology (BPT) represents the application of proven technology that yields the best results having regard for resource conservation, environmental impact, and economics. Best practicable technology should be considered a moving target and constantly reflects the best efforts of engineers and scientists to improve the technical aspects of the recovery or control process as well as its economics.
3. Best Available Technology. Best Available Technology (BAT) represents the application of developing or emerging control technology without regard for

economics. In most cases, it is a technology that is capital- and energy-intensive and is not necessarily proven in Alberta. Normally, best available technology is only applied in response to direct government intervention.

After each industry is examined individually to determine its potential sulphur capacity and forecast emission rate for PT, BPT and BAT, the findings are consolidated for growth scenarios A and B to give a total emission forecast for Alberta.

4.1 NATURAL GAS-BASED SULPHUR

For over thirty years, Alberta has been a major source of natural gas for domestic and export markets. Significant portions of the marketable gas have been produced from sour gas reserves. The production of these reserves has led to the development of a significant supply of elemental sulphur and, in addition, substantial sulphur recovery technology. Current reserves of natural gas, including sour natural gas, and historical production rates are contained in several ERCB reports including Alberta Reserves (ERCB 82-18) and Alberta Oil and Gas Industry Annual Statistics 1981 (ERCB 82-17). These documents, as well as records of all licenced gas-production facilities in Alberta, were the basis for this analysis of sulphur emissions to the atmosphere.

4.1.1 Reserves Characteristics

Alberta's marketable gas and production sulphur are delineated in ERCB Report 82-18 as initial established reserves, ultimate reserves, and remaining established reserves. The ratio of production sulphur to marketable gas is easily calculated and, in fact, is used in estimating ultimate potential for production sulphur. Ratios calculated for initial established reserves, remaining established reserves, and net cumulative production are of considerable interest in analysing the future sulphur production capabilities of Alberta.

In addition to the above ratios, current statistics for actual produced sulphur and actual marketable gas (delivered) are considered in the analysis. Current production of gas shows that the ratio of sulphur to marketable gas is 91.1 $t/10^6m^3$. This ratio peaked at about 128.2 $t/10^6m^3$ during the 1970s and is now trending downward as indicated in Figure 7.

The above trend is also clearly indicated upon examination of the remaining reserves of sulphur and gas. The ratio of initial established sulphur reserves to initial established marketable gas reserves is approximately 72.1 $t/10^6m^3$. However, based on cumulative production to December 31, 1981, the ratio for produced reserves is 90 $t/10^6m^3$ and the ratio for remaining reserves is only 65 $t/10^6m^3$.

In addition, the reserves described above include substantial reserves of sulphur that are contained in unconnected pools with very high H_2S concentrations (above about 70 percent). In the 1982 reserves report the ERCB gives special mention of these reserves. In this report we also consider them separately, and the ratio for remaining reserves excluding these reserves is analysed. The ratio of sulphur to marketable gas with these reserves excluded is about 50 $t/10^6m^3$ as at December 31, 1981.

4.1.2 Production of Reserves

Three possible trends for the sulphur to gas production ratio are examined for the 1982 to 2000 forecast period. The first assumes that the actual production ratio will approach the ratio in the remaining reserves. The second considers the case where the unconnected reserves are removed from the reserves and considered separately. Thirdly, a case is developed with the production ratio held at the actual 1981 production ratio. Each case is analysed for growth scenarios A and B.

Case 1. Each year a new production ratio is calculated based on the ratio of sulphur to gas in the previous year's closing inventory and the previous year's actual production ratio. Inventories of sulphur and gas are adjusted for additions as forecast

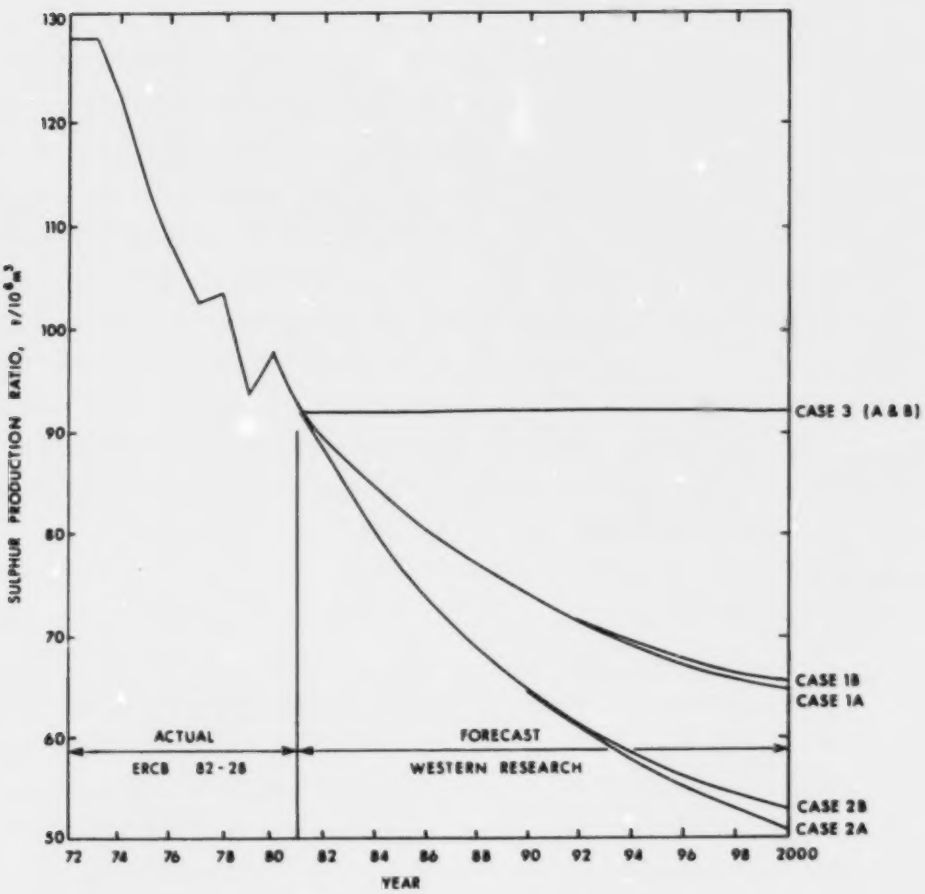

Figure 7. Production ratio of sulphur to marketable gas.

by the ERCB 82-18 (sec. 9, p. 6) and gas production based on either Scenario A or B. The formula used to calculate the production ratio was:

$$PR_{n+1} = f \ PR_n + (1-f) \ IR_n$$

where PR = production ratio
IR = inventory ratio
n = year
f = factor

In our studies, f was set at 0.8 and 0.9, and it was concluded that 0.9 presented a shift in the production ratio that could be achieved by the industry having regard for the commissioning and decommissioning of plants.

The production ratios for the forecast period are also shown in Figure 7. In Figure 8 the production and remaining reserves ratios are shown for the period 1982 to 2000. By 2000 the production ratio is within 10 percent of the remaining reserves ratio and approximately 75 percent of the current 1981 ratio. The difference between gas production rates for scenarios A and B is about two percent for the production ratio and four percent for the remaining reserves ratio.

Case 2. Deletion of the unconnected high sulphur reserves from inventory and application of the same formula resulted in the second set of curves on figures 7 and 8. By 2000 the production ratio is down to 52-55 $t/10^6m^3$, a 40 percent reduction from 1981 levels.

Case 3. If the sulphur production ratio is maintained at present levels a dramatic depletion of sulphur reserves is predicted and by 2000 the ratio in remaining reserves is only 50 percent (Scenario A) and 70 percent (Scenario B) of the 1981 ratio. This is shown in figures 7 and 8. This case would be considered the rapid-depletion case and would require preferential production of sour gas over the forecast period.

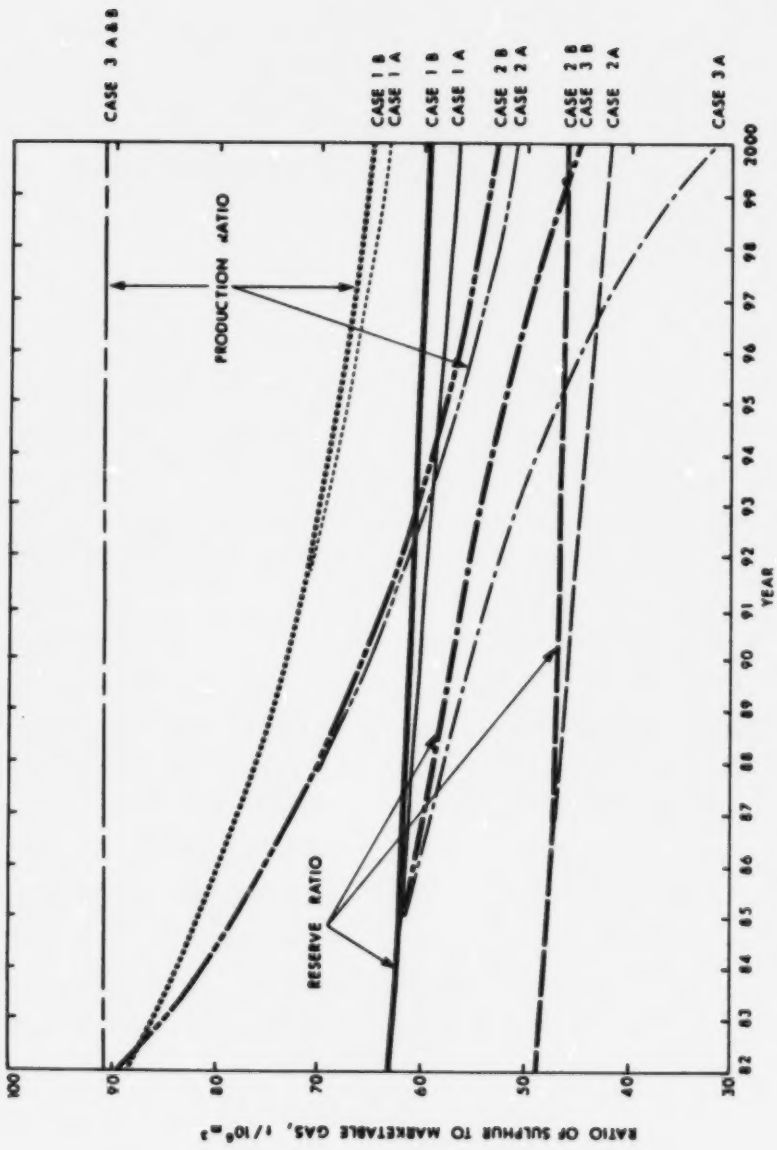

Figure 8. Production ratio and remaining reserves ratio of sulphur to marketable gas.

Production ratio trends for 1972 to 1981 suggest that both Case 1 and Case 2 are reasonable. Substantial changes of sulphur content in new gas finds would probably be required before Case 3 could be maintained for the entire forecast period. With respect to the unconnected high sulphur reserves mentioned in Case 2, it is recognized that technology does not exist presently to produce the reservoir. It is, thus, reasonable to consider the production ratio forecast of Case 2 to be very realistic. The ratios forecast for Case 3 are unrealistically high and those of Case 1 would require new production technology or the discovery of significant new reserves of sour gas, or both.

4.1.3 Sulphur Production

Sulphur production for each of the three cases for both scenarios A and B is presented in Figure 9. Only Case 3 results in sulphur production levels in 2000 that exceed those in 1980. Case 1 Scenario A production levels in 2000 equal those of 1980 while Scenario B levels are 75 percent of present values. For Case 2 scenario A and B levels are, respectively, 80 and 70 percent of present levels.

In all cases gas and sulphur production peaks are forecast for the 1984 to 1988 period.

4.1.4 Potential Sulphur Dioxide Emissions

Sulphur dioxide emissions from gas plants are forecast for the above situations, assuming the application of present technology, best practicable technology and best available technology. In all cases phasing-in periods are allowed.

4.1.4.1 Present Technology. Notwithstanding forecasts, all new gas-processing plants must meet the minimum sulphur recovery requirements of the ERCB (presently specified in ID-80-24). In addition, it is assumed that existing plants that undertake substantial upgrading of facilities will also improve their sulphur

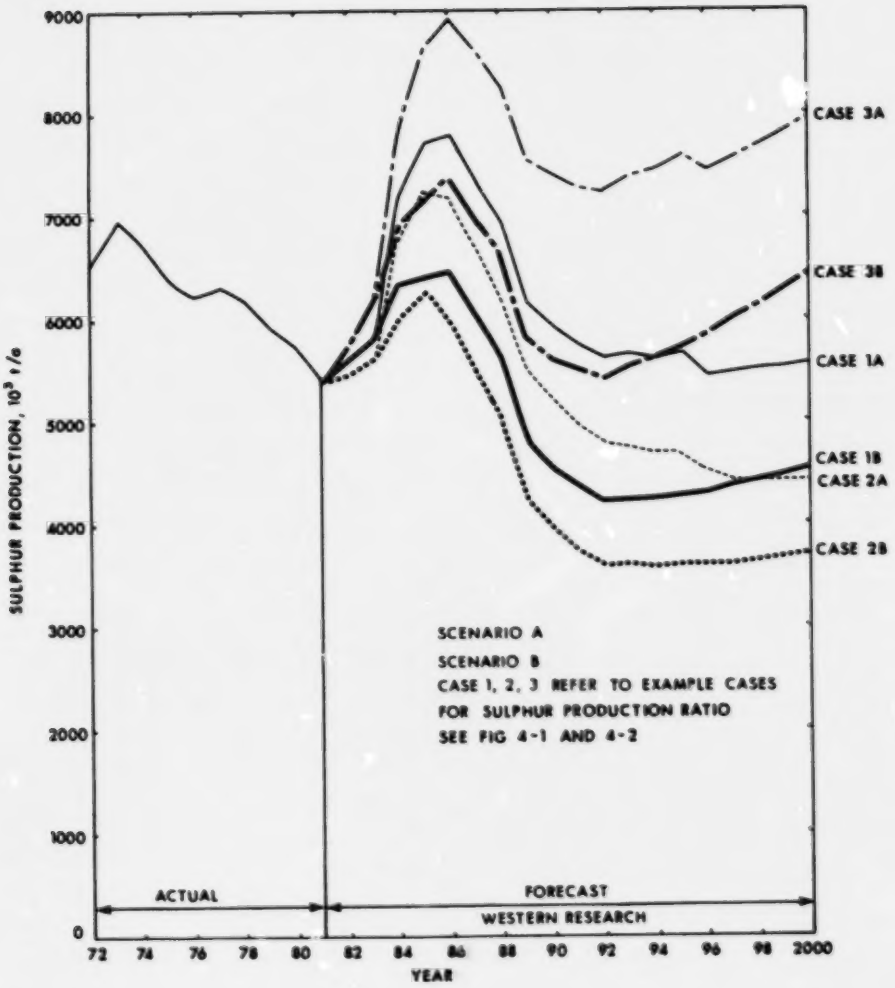

Figure 9. Sulphur production from gas processing plants in Alberta.

recovery systems. The problem remains, however, to predict the average sulphur recovery efficiency for the gas industry for each year to 2000.

Historically, recovery efficiency has improved from essentially no recovery to approximately 97 percent for all licenced plants in 1982 (ERCB 1982; Paskall 1979). Considering all factors, including plant size, age and the development of new facilities, it is assumed that by 2000 the average sulphur recovery efficiency will equal 98.5 percent. This is the maximum practicably attainable efficiency of the 3 stage modified Claus plant (Paskall 1979). A linear improvement from present levels to the 2000 level is applied to the sulphur production forecasts to obtain the sulphur emission forecasts.

4.1.4.2 Best Practicable Technology. Presently, best practicable technology provides recovery efficiencies of 99 to 99.5 percent for large (over 500 t/d) plants. For plants with less than 500 t/d sulphur inlet, best practicable technology provides recovery efficiency of about 97.5 to 98.5 percent. Based on a mix of large and small plants similar to the present mix, the weighted average efficiency with best practicable technology is projected to be 99 percent by 2000.

4.1.4.3 Best Available Technology. Best available technology would provide for 99.5 to 99.9 percent sulphur recovery and, without concern for economics, would be available for all plants. Only with direct government intervention and, possibly, financial support, could an industry-wide recovery efficiency of 99.5 percent be achieved by 2000. Government action is not anticipated to achieve an impact until 1990 due to phase-in and construction schedules. After 1990 the 99.5 percent level in 2000 is assumed to be reached linearly starting from the 1990 best practicable technology levels.

4.1.4.4 Summary. Figure 10 presents historical industry-wide sulphur recovery efficiency from 1961 to 1981 and the above forecast

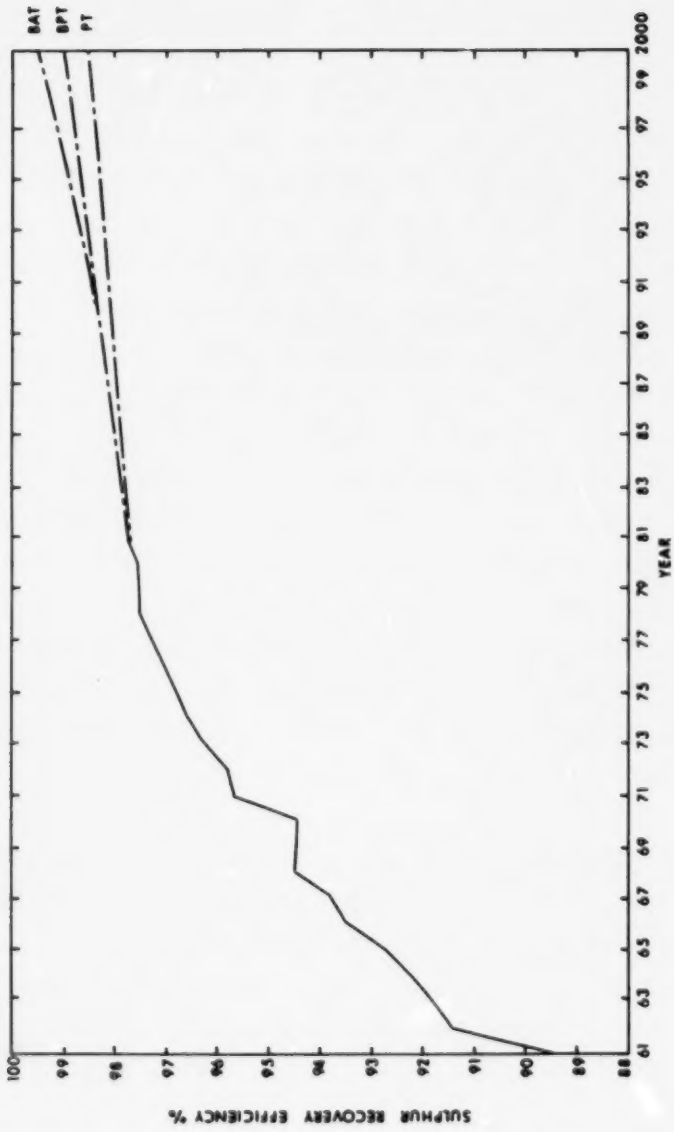

Figure 10. Sulphur recovery efficiency in sour gas processing.

for 1982 to 2000. Figure 11 presents the sulphur dioxide emissions forecast for Scenario A and Scenario B. These levels would be considered to be the actual emission levels for all gas plants. Historical levels of recovery efficiency and emission are also indicated.

The natural gas-based sulphur dioxide emission forecast for Scenario A and Scenario B is tabulated in Table 10.

In addition to the above, it is worthwhile to note actual emission levels and actual licenced levels for the years 1974 to 1981. Clearly, licenced levels in the past have far exceeded actual emission levels and it is anticipated that during the forecast period licenced levels would be higher than the forecast emission levels.

4.2 OIL SANDS-BASED SULPHUR

Alberta Oil Sands are an emerging source of elemental sulphur with significant potential to complement and eventually meet the market demand currently supplied by natural gas-based sulphur. Existing oil sands plants recover 60 to 70 percent of the sulphur processed. The remainder is either retained in the coke or the synthetic crude oil, or released to the atmosphere. It is anticipated that all future oil sands developments will meet present Alberta Environment emission guidelines and that substantially improved sulphur recovery will be achieved.

4.2.1 Reserves Characteristics

The sulphur content of surface mineable and in situ bitumen is about 5 weight percent, of which 60 to 90 percent is removed as the bitumen is upgraded to synthetic crude. Bitumen processing capacity of Suncor and Syncrude has the potential to yield about 440 000 t/a of sulphur but for various reasons production in 1981 was only about 241 000 t (ERCB 82-18). Additional production facilities forecast for Scenario A will increase this potential to approximately 1.08×10^6 t/a by 2000. Actual production of this as elemental sulphur depends on the processes that may be adopted to upgrade the anticipated production.

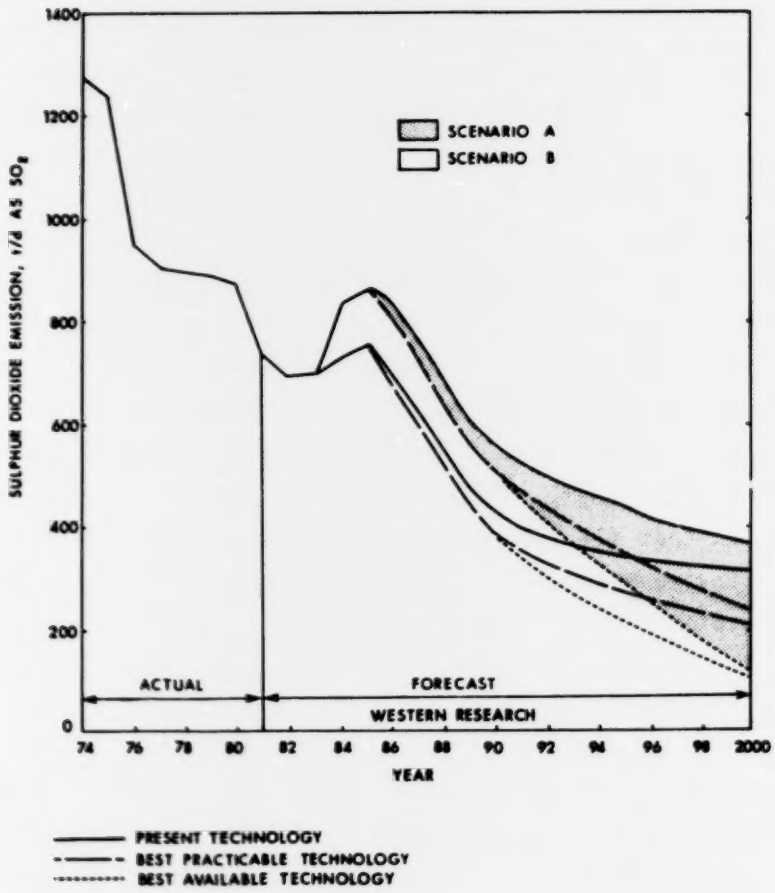

Figure 11. Sulphur dioxide emissions - natural gas industry.

Table 10. Sulphur dioxide emissions forecast for natural gas industry.

Year	Scenario A			Scenario B		
	PT t/d	BPT t/d	BAT t/d	PT t/d	BPT t/d	BAT t/d
1980	868	868	868	868	868	868
1981	723	723	723	723	723	723
1982	692	692	692	692	692	692
1983	696	696	696	696	696	696
1984	832	832	832	832	832	832
1985	866	866	866	750	750	750
1986	844	824	824	698	680	680
1987	764	738	738	624	602	602
1988	700	664	664	560	532	532
1989	602	560	560	466	434	434
1990	560	510	510	426	388	388
1991	520	466	450	396	354	342
1992	494	432	402	372	326	304
1993	478	406	366	364	308	278
1994	460	380	326	350	290	248
1995	450	360	294	344	274	224
1996	416	326	248	334	268	198
1997	404	306	216	328	250	176
1998	394	284	186	324	232	154
1999	382	266	154	318	220	128
2000	370	246	122	310	206	102

For Scenario B, no new sulphur production is forecast and the potential production will remain at its present level.

4.2.2 Potential Sulphur Dioxide Emissions

Licenced sulphur emissions and actual emissions are expected to reflect the actual load factor for the various plants and not the demand for crude. Actual emission levels are anticipated to be 70 to 90 percent of licenced levels. To be conservative in this forecast, potential future emissions are estimated to be 90 percent of licenced emissions on an annual average basis, except when emission control equipment is applied. Forecasts are presented for application of present, best practicable, and best available technology.

4.2.2.1 Present Technology. Present technology reflects the current emission guidelines for Suncor and Syncrude as well as the Alberta Environment guidelines for new projects of 3.15 t of sulphur dioxide emission per 1000 m^3 of bitumen to upgrading. In that Canstar had indicated that they would achieve the guideline (S. Dobko: pers. comm.) it is assumed that this level represents present technology as well as best practicable for new plants.

For Scenario A it is assumed that all plants would discharge 90 percent of licenced emissions when averaged on an annual basis. This includes existing and future operations. For Scenario B only the emissions of Suncor and Syncrude are expected and, again, 90 percent of licenced levels is assumed.

4.2.2.2 Best Practicable Technology. Achieving best practicable sulphur dioxide emission control at all operating oil sands plants would have substantial impact on sulphur emissions in northeast Alberta. The resultant sulphur dioxide emission forecast, assuming Suncor and Syncrude achieve best practicable control in a two-step approach with emission reductions in 1987 and 1992, is presented in Figure 12.

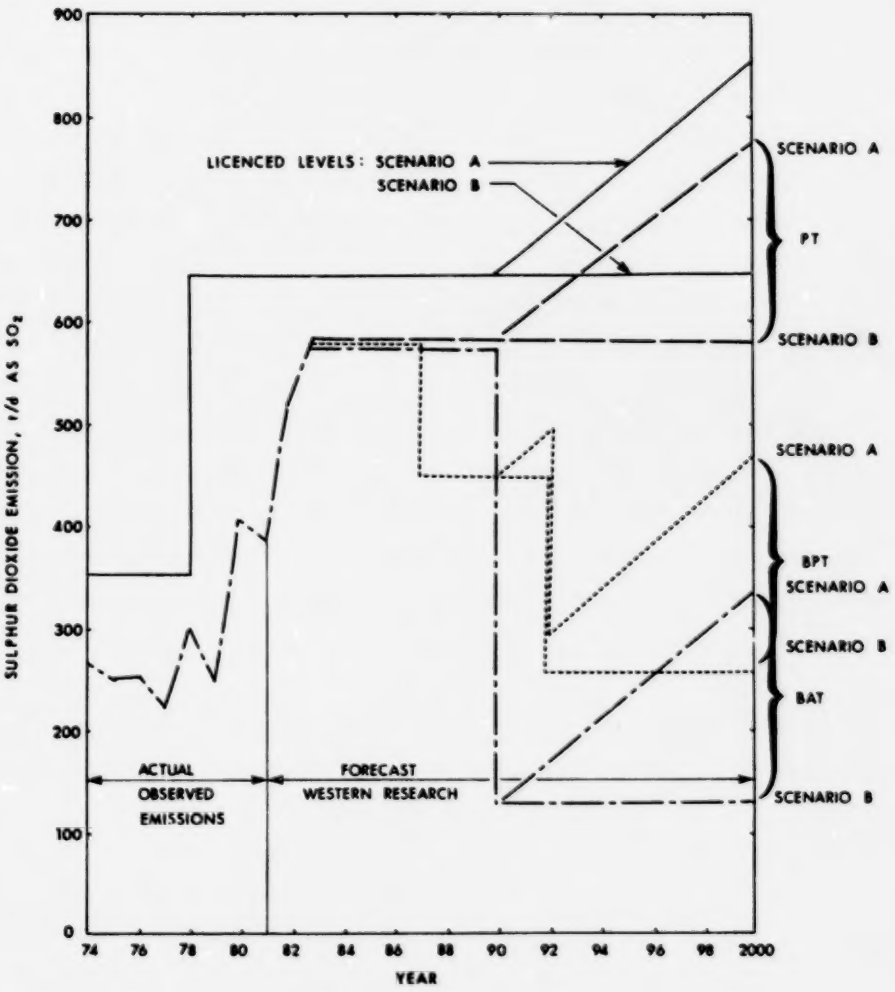

Figure 12. Sulphur dioxide emissions - oil sands.

For both Suncor and Syncrude, sulphur dioxide emission reductions would probably be achieved without sulphur recovery; thus, no revenue would be generated. Several processes are available for controlling sulphur dioxide emissions and, if required, it is expected that either lime or limestone wet scrubbers, or dry additive fabric filtration systems would be employed. Neither have been tested in a northern climate and, as a consequence, a lower reliability factor has been assigned to the emission control system than has previously been reported for flue-gas desulphurization systems (Laseke et al. 1982).

Application of flue-gas desulphurization technology would be expected to result in an annual average sulphur dioxide emission reduction for Suncor and Syncrude of 60 to 70 percent. In the forecast presented in Figure 12, best practicable technology has been estimated at 60 percent control (annual average) and this has been applied to existing plants in two steps: 30 percent in 1987 and 30 percent in 1992. Emissions are assumed to reduce to 70 and 40 percent of present licenced levels as a result of the application of best practicable technology in this two-step process.

4.2.2.3 Best Available Technology. Best available technology for existing plants is assumed to be 80 percent control through flue-gas desulphurization technology. The earliest possible date that this could be achieved is estimated to be 1990 and emissions are estimated to be 20 percent of present licenced levels. New plants are forecast to achieve the Alberta Guideline of 3.15 t/1000 m^3 bitumen to upgrading. Resultant sulphur emissions for oil sands plants using best available technology are shown in Figure 12.

Table 11 summarizes the oil sands-based sulphur dioxide emission forecast for Scenario A and Scenario B.

4.3 ELECTRIC UTILITY-BASED SULPHUR

Electricity requirements in Alberta are met primarily by thermal power plants using low sulphur coal. This is expected to continue for the foreseeable future and, as indicated in Chapter 3,

Table 11. Sulphur dioxide emissions forecast for oil sands.

Year	Scenario A			Scenario B		
	PT t/d	BPT t/d	BAT t/d	PT t/d	BPT t/d	BAT t/d
1980	403	403	403	403	403	403
1981	387	387	387	387	387	387
1982	540	540	540	540	540	540
1983	581	581	581	581	581	581
1984	581	581	581	581	581	581
1985	581	581	581	581	581	581
1986	581	581	581	581	581	581
1987	581	581	581	581	581	581
1988	581	452	581	581	452	581
1989	581	452	581	581	452	581
1990	581	452	581	581	452	581
1991	600	473	150	581	452	129
1992	619	494	171	581	452	129
1993	638	321	192	581	258	129
1994	657	342	213	581	258	129
1995	681	363	234	581	258	129
1996	695	384	255	581	258	129
1997	714	405	276	581	258	129
1998	733	426	297	581	258	129
1999	752	447	318	581	258	129
2000	770	468	339	581	258	129

the growth of coal-fired power plants over the forecast period will be significant.

4.3.1 Sulphur Content of Coal

Thermal coal now used or proposed for use in Alberta contains from 0.2 to 0.7 percent sulphur. For coal with an average heat content of 18 x 10^6J/kg, the sulphur dioxide emission potential ranges from 222 ng/J to 778 ng/J of heat input. These values may be compared to the present federal emission guidelines for new generating units of 258 ng/J for units with emission potentials of from 258 to 2580 ng/J (Canada Environment Clean Air Act 1981). Alberta Environment has also adopted the federal guidelines and now uses them in its evaluation of proposed coal-fired units.

The sulphur dioxide emission potential of existing and future coal-fired power plants in Alberta is contained in the EUPC report, "Power Generation in Alberta, Base Data" (1981), and has been reported, in part, by Behie et al. (1980). Pertinent data for the plants is summarized in Table 12. Plants at sites with coal deposits containing 0.23 percent sulphur would, theoretically, meet the federal guideline for sulphur dioxide emissions. Examination of all existing and approved plants shows that three plants, representing about 28 percent of total thermal generating capacity, burn coal that exceeds 0.23 percent sulphur. The total weighted average sulphur content in the coal used by existing plants is 0.26 percent. Of the future sites, only potential plants at Genessee and Keephills will meet the 0.23 percent sulphur requirement and the weighted average sulphur content is 0.39 percent. Consequently, the potential sulphur dioxide emissions per unit of electric energy produced will be increasing.

4.3.2 Electric Utility Growth

In order to forecast sulphur dioxide emissions, existing and approved generating units have been assumed operational at a 70 percent load factor (except for Wabamun for which a 50 percent total

Table 12. Existing and potential coal-fired power plants.[a]

Station Name	Nominal Size MW		Percent Sulphur in Coal		Potential Sulphur Emission t/d
A. Existing or Under Construction					
Wabamun	582[b]		0.22		30.4
Sundance	2100		0.20		107.5
HR Milner	140		0.32		9.4
Battle River	735		0.40		59.0
Keephills 1 & 2	800		0.20		22.6
Genessee 1 & 2	800		0.21		22.4
Sheerness 1 & 2	800		0.45		57.2
Subtotal	5927	Weighted Av.	0.263	Subtotal	308.5
B. Potential Future Plants					
Keephills 3 & 4	800		0.20		23
Genessee 3 & 4	800		0.21		22
Camrose Riley	2250		0.60		190
Alix	1500		0.30		67
Bow City - Kitsim	1000		0.70		86
Isle Lake	1500		0.45		106
Judy Creek	2250		0.33		143
Pipestone	1500		0.30		62
Picardville	1500		0.27		55
Blackfoot	1500		0.42		83
Lesser Slave Lake	750		c		42[d]
Fox Creek	750		c		42[d]
Trochu - Three Hills	750		c		42[d]
Subtotal	16850	Weighted Av.	0.39	Subtotal	963
Total of A + B	22777	Weighted Av.	0.36	Total	1272

[a] Source: Part A - J. Jaferi (Alberta Environment). 1982. Personal communication.
Part B - Electric Utilities Planning Council. 1981. Power generation in Alberta, base data; Behie and Johnson 1980; Western Research interpolation.

[b] Assumes all coal-fired

[c] Not available - not included in average

[d] Estimated based on weighted average sulphur content for all plants

station load factor was assumed) as required to satisfy the forecast demand for Scenarios A and B. These include Wabamun 1-4, Sundance 1-6, Battle River 1-5, H.R. Milner, Keephills 1-4, Genessee 1 and 2 and Sheerness 1 and 2. Additions are allocated consistent with the order of ERCB approvals.

Beyond these approved plants, the average sulphur dioxide emission potential per GW h of energy required, calculated based on the average coal energy content of 18 x 10^6 J/kg and an average coal sulphur content of 0.39 percent, was used to forecast emissions.

Table 13 summarizes the utility capacity that will be required to be in service for the two growth scenarios and for the two options (all coal and coal plus non-thermal).

4.3.3 Potential Sulphur Dioxide Emissions

Sulphur dioxide emissions forecasts are presented for both growth scenarios and the "all-coal" and "coal plus non-thermal" options. Forecasts include the application of present, best practicable and best available technology.

4.3.3.1 Present Technology. Present technology in Alberta for coal-fired power plants is no sulphur dioxide emission control and no precleaning of raw coal to minimize sulphur input to the boiler.

The forecast emissions and historical emissions from existing plants are presented in Figure 13 and summarized in Table 14. For comparison purposes, anticipated licenced emission levels (at maximum continuous rating) and anticipated observed levels are shown for the forecast period. Anticipated observed levels are expected to be about 70 percent of licenced levels.

4.3.3.2 Best Practicable Technology. Best practicable technology is considered to be the application of control technology that would bring each new boiler or, alternately, each new station into compliance with the 258 ng/J sulphur dioxide emission guideline. Control of a station would probably provide the greatest number of

Table 13. Thermal power plant capacity additions.

	Scenario A		Scenario B	
	All Coal	Coal plus non thermal	All Coal	Coal plus non thermal
1980	Wabamum[a] 1, 2, 3 & 4 Sundance[b] 1, 2, 3, 4 & 5 Battle River[c] 1, 2, 3 & 4 HR Milner[d] 1	Same	Same	Same
1985	Sundance 6 Battle River 5 Keephills[e] 1 & 2 Sheerness[f] 1 & 2	Sundance 6 Battle River 5 Keephills 1 & 2 Sheerness 1 & 2	Sundance 6 Battle River 5 Keephills 1 & 2 Sheerness 1	Sundance 6 Battle River 5 Keephills 1 & 2 Sheerness 1
1990	Genessee[g] 1 & 2 U800[h]	Genessee 1 & 2 U800	Sheerness 2 Genessee 1 & 2	Sheerness 2 Genessee 1
1995	U1500	None	U1180	None
2000	U1850	U2172	U1150	Genessee 2 U1160

Note
[a] Wabamum - 50 percent load factor
[b] Sundance - 70 percent load factor
[c] Battle River - 70 percent load factor
[d] HR Milner - 50 percent load factor
[e] Keephills - 70 percent load factor
[f] Sheerness - 70 percent load factor
[g] Genessee - 70 percent load factor
[h] Unidentified - 70 percent load factor

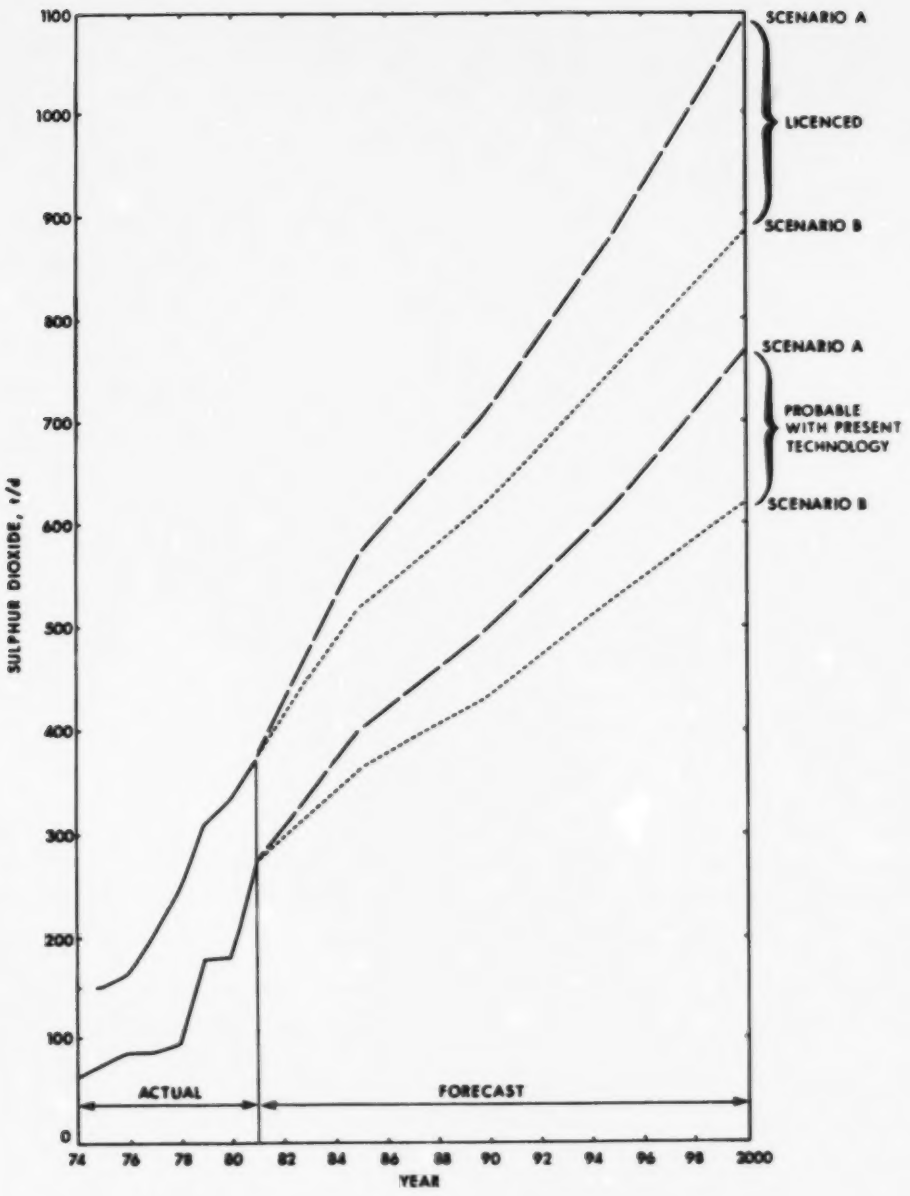

Figure 13. Power plant licenced and probable sulphur dioxide emissions - present technology.

Table 14. Sulphur dioxide emissions forecast for electric utilities.

Year	Scenario A			Scenario B		
	PT t/d	BPT t/d	BAT t/d	PT t/d	BPT t/d	BAT t/d
1980	180	180	180	180	180	180
1981	272	272	272	272	272	272
1982	304	304	304	295	295	295
1983	336	336	336	317	317	317
1984	368	368	368	340	340	340
1985	400	400	400	362	362	362
1986	419	414	408	376	376	376
1987	438	427	415	390	390	390
1988	458	441	423	404	404	404
1989	477	454	430	418	418	418
1990	496	468	438	432	432	432
1991	520	481	362	451	442	356
1992	545	494	285	470	453	281
1993	569	508	209	488	463	205
1994	594	521	132	507	474	130
1995	618	534	56	526	484	54
1996	647	550	60	544	484	56
1997	676	567	65	563	505	57
1998	706	583	69	581	515	59
1999	735	600	74	600	526	60
2000	764	616	78	618	536	62

options for the utility and would be the most cost-effective way of achieving the emission guidelines. Flue gas desulphurization technology is available to achieve the 258 ng/J sulphur dioxide emission guideline (Laseke et al 1982).

For existing and approved units, best practicable technology has been taken as no control, based on the premise that retrofit flue gas desulphurization systems would cost from 50 to 75 percent more than systems incorporated in the original design of the unit.

For this forecast, control of emissions from new units on a station basis sufficient to meet the 258 ng/J heat input guideline and no control on existing and approved plants has been adopted as best practicable control. The resultant forecasts are summarized in Table 14 and indicated in Figure 14 along with the forecasts for present technology for comparison purposes.

4.3.3.3 Best Available Technology. Flue gas desulphurization systems currently available in North America are capable of from 80 to 90 plus percent sulphur emission control, and for low-sulphur coals have averaged 90 to 94 percent availability over the period 1978 to 1981 (Laseke et al 1982). Thus, best available technology would imply 90 percent control on all boilers. The least expensive method of achieving best available technology would be to apply full emission control on all future units. On the other hand, application of best available technology to all units would have the most significant impact on emissions, as well as the largest adverse impact on electricity costs. Adopting best available technology at all stations would result in actual emissions substantially below the federal guideline and equivalent to about 40 ng/J heat input.

For this forecast it is assumed that best available technology is applied to all existing stations in the 1990 to 1995 time period and to new units when constructed. The resulting emissions forecast is shown in Figure 14 and summarized in Table 14.

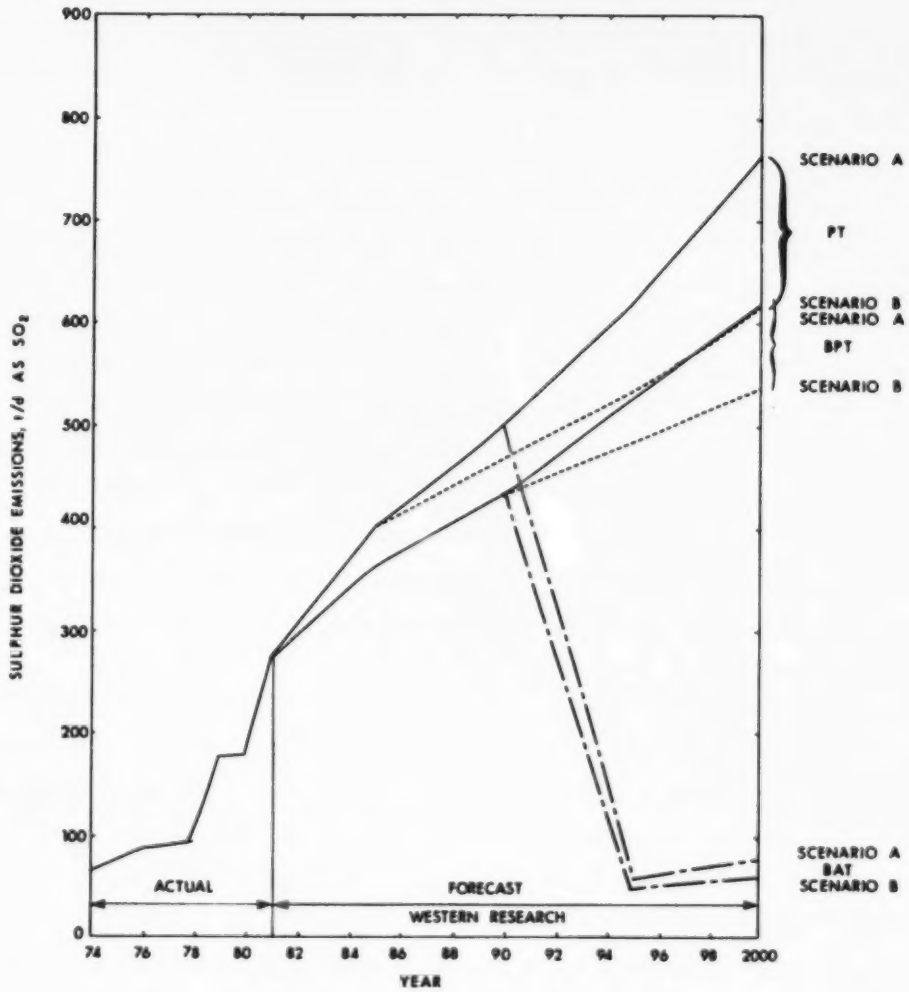

Figure 14. Sulphur dioxide emissions - coal-fired power plants.

4.3.4 Other Options

4.3.4.1 Carbon Dioxide Recovery. Carbon dioxide recovery from flue gases generated by coal-fired power plants may provide an interesting opportunity to reduce sulphur dioxide emissions. During the carbon dioxide recovery process essentially all sulphur oxides are removed from the flue gases and converted to a solid waste.

Government programs to encourage tertiary oil recovery using carbon dioxide recovered from coal-fired power plants with sulphur emission rates that may exceed the federal guideline, may result in a positive impact on efforts to reduce sulphur dioxide emissions. As an example, the recovery of $28 \times 10^6 m^3/d$ of carbon dioxide for enhanced oil recovery projects by 2000 was considered and the impact of sulphur removal on the total potential sulphur dioxide emissions of electric utilities was calculated.

To achieve the above-mentioned production of carbon dioxide, the flue gas from a 3750 MW station would have to be processed. The estimated sulphur dioxide emissions reduction would be about 150 to 300 t/d.

4.4 OTHER INDUSTRIES

Other industries in Alberta which emit sulphur dioxide include conventional crude oil, fertilizer, pulp and paper, refinery and sulphur-containing chemical manufacturing operations. The combined sulphur dioxide emissions from these industries are relatively small compared with the major emitters in Alberta (i.e., natural gas, oil sands and electric utilities).

Conservative estimates of their sulphur dioxide emissions are made in the following sections.

4.4.1 Conventional Crude Oil-Based Sulphur

Crude oil under pressure in its natural state in the reservoir may contain dissolved gas called "solution gas". When the oil is produced, the solution gas separates from the oil as the

pressure is reduced. It is the stated policy of the Energy Resources Conservation Board to conserve as much solution gas as is economically possible. As a result, production data of oil pools where solution gas is not fully conserved are continually reviewed by the ERCB. When the ERCB observes that the volume of solution gas flared or the values of gas conserved and co-products become significant, an economic feasibility evaluation will be carried out either by the ERCB or the operator concerned and submitted to the ERCB. After reviewing the economic evaluation, the ERCB may conclude that conservation of solution gas is economical and may order the implementation of a conservation program by the issuance of a gas conservation (GC) order.

In 1980, about 91 percent of the solution gas was conserved, while the remaining 9 percent was flared. The portion of flared solution gas which contains sulphur results in sulphur dioxide emissions. Based on available data (Alberta Environment 1979 and 1982), it is estimated that the solution gas-based sulphur dioxide emissions in 1980 were 95.9 t/d.

It should be noted that the present technology, best practicable technology and best available technology for the processing of sour natural gas can be suitably applied to the processing of sour solution gas. As the sulphur recovery efficiency of the present technology is already high (i.e., approximately 97 percent recovery efficiency), the solution gas-based sulphur dioxide emissions depend almost entirely on the conservation policy of the Board (i.e., the amount of solution gas the Board allows to be flared). It is our opinion that the Board's policy for solution gas conservation will remain unchanged and the amount of solution gas conserved will remain at about 91 percent for technical and economic reasons (Wolf 1981). Thus the sulphur dioxide emissions forecasts assuming the application of present technology, best practicable technology, and best available technology are essentially identical, and are conservatively estimated to decline proportionally to the rate of decline of conventional crude oil production in Alberta.

4.4.2 Fertilizer-Based Sulphur

Fertilizer-based sulphur dioxide emissions result mostly from the sulphuric acid manufacturing operation of the industry. Based on available data (Alberta Environment 1979 and 1982), the actual sulphur dioxide emissions from the fertilizer industry in Alberta in 1980 were estimated to be 22 t/d. Brief descriptions of control technology and emissions forecasts are presented in the following sections.

4.4.2.1 Present Technology. For economic and environmental reasons, fertilizer plants in Alberta have converted, or are converting, to the double conversion/double absorption (DC/DA) process for their sulphuric acid manufacturing operation. This, together with continuous stack monitoring for process adjustments, represents, in our opinion, the best practicable technology for the control of sulphur dioxide emissions from sulphuric acid plants of the fertilizer industry. Sulphur dioxide emissions of 2 kg/t of 100 percent acid produced are achievable with the application of this technology.

4.4.2.2 Best Practicable Technology. For the reason noted above, best practicable technology is assumed to be essentially identical to the present technology applied by the industry in Alberta.

4.4.2.3 Best Available Technology. Best available technology is considered to be exhaust gas scrubbing and molecular sieves to control the effluents of the DC/DA process. This, however, will impose additional penalties in the form of unwanted by-products and higher manufacturing costs to the industry. Increased government action will be required before application of this technology by the industry in Alberta, and the adoption of best available technology is not anticipated to achieve any impact before 1990 due to phase-in and construction schedules. Sulphur dioxide emissions of 0.5 kg/t of 100 percent acid produced are conservatively estimated to be achievable by this technology.

4.4.2.4 Scenario A. With the application of present technology and best practicable technology, the sulphur dioxide emissions from the present sulphuric acid production capacity in Alberta are expected to drop from 22 t/d in 1980 to 14 t/d after 1985 for the remainder of the forecast period. The expansions of Alberta capacity in 1990 and 1993 are expected to increase the sulphur dioxide emissions by 2 t/d in 1990 and again in 1993.

With the application of best available technology, sulphur dioxide emissions of the present sulphuric acid production capacity are expected to decline significantly after 1990; a linear reduction to 5 t/d by 2000 is assumed. The expansions of 1990 and 1993 are expected to increase the sulphur dioxide emissions by 0.5 t/d for each expansion.

4.4.2.5 Scenario B. In the low growth scenario, no additional plants are forecast to be built until after 2000. With the application of present technology and best practicable technology, the sulphur dioxide emissions are expected to decline from the present level of 22 t/d to 14 t/d after 1985 and for the remainder of the forecast period. With the application of best available technology, sulphur dioxide emissions are expected to decline significantly after 1990; a linear reduction to 5 t/d by 2000 is assumed.

4.4.3 Pulp and Paper-Based Sulphur

Pulp and paper-based sulphur dioxide emissions result mostly from the recovery boiler operation of the two kraft pulp mills in Alberta - the St. Regis mill in Hinton, and the Proctor and Gamble mill in Grande Prairie. Based on available data (Alberta Environment 1979 and 1982), the actual sulphur dioxide emissions from the pulp and paper industry in Alberta were estimated to be 18 t/d in 1980. Brief descriptions of control technology and emission forecasts are presented in the following sections.

It should be noted that odour from total reduced sulphur compounds (TRS) and particulates emissions are usually the main

issues addressed by the kraft pulping industry. Sulphur dioxide emissions are usually small and are not addressed specifically. As a result, control technologies for sulphur dioxide are only developed coincidentally with the development of technologies for TRS and particulates emission control.

4.4.3.1 Present Technology. Present technology applied by the kraft pulping industry for TRS emission control is the installation of a low-odour recovery boiler, and, for particulate emission control, the installation of electrostatic precipitators. Both have minor impact on sulphur dioxide emissions.

4.4.3.2 Best Practicable Technology. Since the selective removal of sulphur dioxide emissions is not economically viable for kraft pulp mills, a low-odour recovery boiler and electrostatic precipitators also represent best practicable technology. Minor impact on sulphur dioxide emissions is expected.

4.4.3.3 Best Available Technology. Best available technology is considered to be the installation of a sulphur dioxide scrubber for the exhaust gas of the low-odour recovery boiler with electrostatic precipitators. Since installation of the scrubber is not, in our opinion, economically viable, this technology will not be applied by the industry without increased government actions. As a result, impact on sulphur dioxide emissions would not be achieved before 1990 due to construction schedule and phase-in problems.

4.4.3.4 Scenario A. With the application of present technology and best practicable technology, the sulphur dioxide emissions from the two kraft mills in Alberta are expected to remain relatively unchanged at 18 t/d during the forecast period. The proposed British Columbia Forest Product (BCFP) mill near Whitecourt and the development of the Brazeau Timber Block are assumed to be based on thermal mechanical pulping (TMP) for environmental and economic reasons (EUPC 1981), and are expected to have minor impact on the sulphur dioxide emissions forecast.

With the application of best available technology, sulphur dioxide emissions from the two kraft mills in Alberta are expected to be reduced significantly after 1990; a linear improvement to 3 t/d by 2000 if 85 percent efficiency of the scrubber is assumed.

4.4.3.5 Scenario B. The sulphur dioxide emissions forecast for the low growth scenario is essentially identical to that of the high growth scenario, since the expected developments are assumed to have minor impact on sulphur dioxide emissions.

4.4.4 Refinery-Based Sulphur

Refinery-based sulphur dioxide emissions result mostly from the sulphur recovery and catalyst regeneration operation of the industry. Based on available information (Alberta Environment 1979 and 1982), the sulphur dioxide emissions from the refinery industry in Alberta were estimated to be 40 t/d in 1980. Brief descriptions of control technology and emission forecasts are presented in the following sections.

4.4.4.1 Present Technology. Present technology for the sulphur recovery plant is considered to be a Claus process with approximately 97 percent sulphur recovery efficiency. Exhaust gas from the catalyst regeneration operation is either burned in a waste heat boiler to generate additional steam, or vented directly into the atmosphere. Present technology is no control of sulphur dioxide emissions from this source.

4.4.4.2 Best Practicable Technology. Best practicable technology for the sulphur recovery plant is considered to be a Claus process with approximately 98.5 percent sulphur recovery efficiency. Since removal of sulphur dioxide from the exhaust of the catalyst regeneration system is not economically practical, best practicable technology is considered to be no control of sulphur dioxide emissions from this source.

4.4.4.3 Best Available Technology. Best available technology for the sulphur recovery plant is considered to be a Claus process with a tail gas clean-up unit with 99.9 percent sulphur recovery efficiency. Best available technology for the removal of sulphur dioxide from the exhaust of the catalyst regeneration system is considered to be a scrubbing unit with approximately 85 percent efficiency.

4.4.4.4 Scenario A. With the application of present technology and best practicable technology, the sulphur dioxide emissions from the installed refining capacity in Alberta are expected to decline slightly, to 36 t/d by 2000, mainly as a result of the improvement of sulphur recovery efficiency of the sulphur plant during the forecast period. The expansions of refining capacity of 3200 m^3/d in 1990 and 8000 m^3/d in 1995 are expected to increase the sulphur dioxide emissions by 2 t/d and 4 t/d, respectively.

Due to phase-in and construction schedules, the application of best available technology and its impact on sulphur dioxide emissions would not be achieved before 1990. However, after 1990, the sulphur dioxide emissions from refineries in Alberta are expected to decline significantly and a linear improvement to 10 t/d by 2000 is estimated. The expansions of refining capacity of 3200 m^3/d in 1990 and 8000 m^3/d in 1995 are expected to increase the sulphur dioxide emissions by 0.5 t/d and 2 t/d, respectively.

4.4.4.5 Scenario B. With the application of present technology and best practicable technology, the sulphur dioxide emissions forecast for the installed refining capacity in Alberta is the same as that for Scenario A. The expansion of refining capacity of 4000 m^3/d in 1993 is expected to increase the sulphur dioxide emissions by 2 t/d.

With the application of best available technology, the sulphur dioxide emissions forecast for the installed refining capacity in Alberta is similar to that of Scenario A. The addition of 4000 m^3/d refining capacity in 1993 is expected to increase the sulphur dioxide emissions by 0.5 t/d.

4.4.5 Others

Two other sources, Alcan and Thio-Petchem, were mentioned in section 3 and are identified in the inventory of sulphur dioxide emissions (Alberta Environment 1979 and 1982). Although action may be taken by each of the two plants to reduce their emissions over the forecast period, they have been assumed constant at 14 t/d total licenced emissions.

4.4.6 Summary

The sulphur dioxide emissions of the industries outlined in this section are summarized in Figure 15 and individually tabulated in Table 15.

4.5 TOTAL ALBERTA FORECAST

4.5.1 Consolidated Forecast

Each individual industry forecast was examined in detail and representative development scenarios and emissions forecasts were carried through to prepare a consolidated forecast of sulphur dioxide emissions in Alberta for the period 1980-1982. In addition, historical emissions for the period 1974 to 1981 were also summarized.

The following were considered representative situations.

4.5.1.1 Scenario A.

1. Natural Gas. High growth corresponding to expanded USA and expanded Canadian markets. The ratio of sulphur to marketable gas produced was estimated by subtracting unconnected high sulphur reserves from the inventory (Case 2).
2. Oil Sands. High growth corresponding to an increase in capacity to a total of 84 000 m^3/d of synthetic crude.

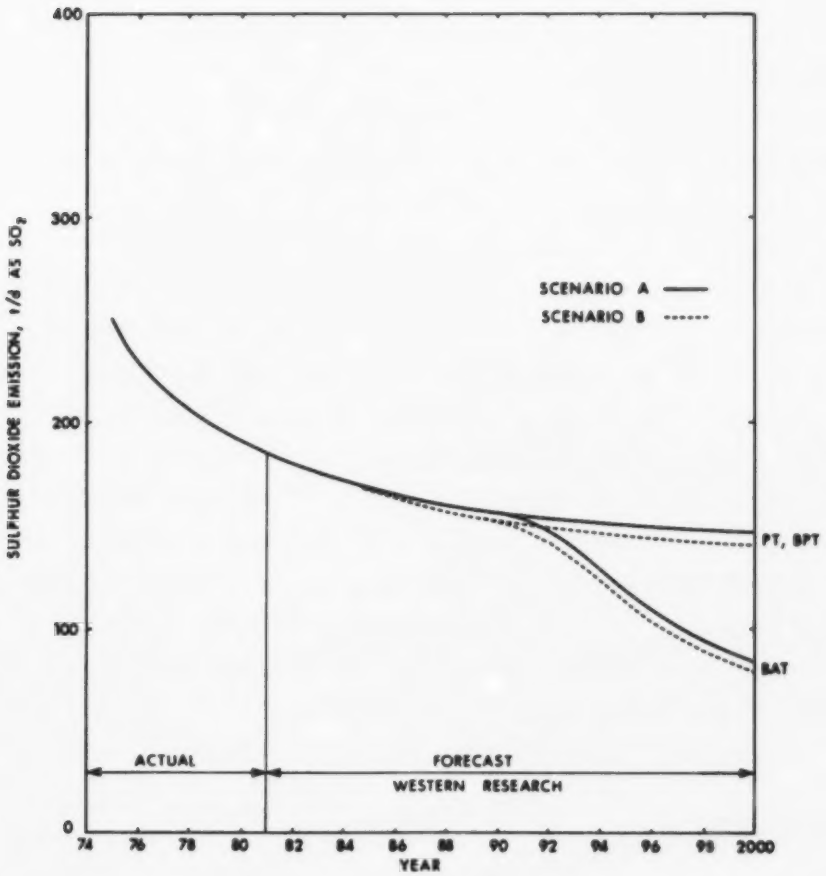

Figure 15. Sulphur dioxide emissions - other industries.

Table 15. Sulphur dioxide emissions forecasts for other industries.

	1975 t/d	1980 t/d	1985 t/d	1990 t/d	1995 t/d	2000 t/d
A. Conventional Crude Oil						
Scenario A & B	109[a]	96	74	60	50	45
B. Fertilizer Industry						
Scenario A						
Present Technology	37	22	14	16	18	18
Best Practicable Technology	37	22	14	16	18	18
Best Available Technology	37	22	14	14	10	5
Scenario B						
Present Technology	37	22	14	14	14	14
Best Practicable Technology	37	22	14	14	14	14
Best Available Technology	37	22	14	14	9	4
C. Pulp and Paper Industry						
Scenario A & B						
Present Technology	37[b]	18	18	18	18	18
Best Practicable Technology	37	18	18	18	18	18
Best Available Technology	37	18	18	18	11	3
D. Refinery Industry						
Scenario A						
Present Technology	53	40	39	40	43	42
Best Practicable Technology	53	40	39	40	43	42
Best Available Technology	53	40	39	40	26	13
Scenario B						
Present Technology	53	40	39	38	39	38
Best Practicable Technology	53	40	39	38	39	38
Best Available Technology	53	40	39	38	25	11
E. Others						
Scenario A & B	14	14	14	14	14	14

[a] Data for 1975 were not available, figures shown are for 1978
[b] Data for 1975 were not available, figures shown are for 1976

3. Electric Power. High growth forecast with the maximum supply of electrical energy coming from coal-fired power plants.
4. Solution Gas. Maximum deliverability of conventional oil and no change in policy regarding solution gas conservation.
5. Other Industries. Anticipated highest growth rate for each segment. This category represents about 10 percent of total emissions by the year 2000 if BAT is applied; otherwise it is a minor contributor to total emissions.

Population anticipated by this scenario is 3.8 million by 2000.

4.5.1.2 Scenario B.

1. Natural Gas. Lowest growth forecast corresponding to the supply of Alberta and traditional Canadian demands as well as meeting the existing USA export licences.
2. Oil Sands. This scenario anticipates no additional oil sands plants during the forecast period.
3. Electric Power. This low-growth forecast combines reduced industrial and population growth forecasts but still assumes maximum use of coal to supply the required energy.
4. Solution Gas. The same solution gas forecast is assumed for this scenario as for scenario A.
5. Other Industries. A low growth profile is anticipated. This category represents about 20 percent of the emissions by 2000 when BAT is applied. For PT and BPT its contribution is negligible.

Population anticipated by this scenario is 3.0 million by 2000.

4.5.1.3 Comments. The forecast emissions for these two scenarios are outlined in Table 16 and Figure 16.

Some general comments about the forecast are appropriate but first it should be made clear that:

1. The forecast does not attempt to present licenced emissions. It attempts to present emission levels that may actually be observed. Typically, observed levels are 50 to 65 percent of licenced levels.
2. The text examines situations that may lead to emissions greater than, as well as less than, those presented in this summary. Reference should be made specifically to section 4.1 for natural gas and section 4.3 for coal fired power plants.

Figure 16 clearly demonstrates that emissions of sulphur dioxide are independent of technology until about 1985, and that significant impacts of applying improved sulphur recovery or sulphur dioxide emission control equipment will not be realized until the late 1980s and early 1990s.

The forecast suggests that present technology, as applied to all industries, will not ensure zero growth of sulphur dioxide emissions from Alberta sources. Only under the low growth scenario would this be possible, if at all.

Best practicable technology, as interpreted by the authors for the various industries in Alberta, appears to adequately control emissions for both high and low growth scenarios. At a minimum, emissions should not exceed present levels and may even be substantially less than the lowest levels recorded between 1974 and 1981.

Best available technology has the capability to reduce emission levels to about one-third of present levels.

Table 16. Consolidated Alberta sulphur dioxide emissions forecast.

Year	Scenario A			Scenario B		
	PT t/d	BPT t/d	BAT t/d	PT t/d	BPT t/d	BAT t/d
1980	1641	1641	1641	1641	1641	1641
1981	1565	1565	1565	1565	1565	1565
1982	1712	1712	1712	1703	1703	1703
1983	1784	1784	1784	1765	1765	1765
1984	1955	1956	1956	1827	1827	1827
1985	2006	2006	2007	1852	1852	1852
1986	2000	1975	1970	1811	1793	1793
1987	1736	1899	1888	1748	1726	1726
1988	1889	1708	1819	1695	1538	1666
1989	1806	1615	1718	1611	1450	1579
1990	1783	1578	1674	1583	1416	1545
1991	1784	1566	1100	1570	1390	965
1992	1800	1564	988	1563	1371	844
1993	1826	1379	890	1572	1168	734
1994	1850	1386	788	1575	1159	622
1995	1888	1400	695	1586	1151	516
1996	1896	1402	667	1593	1154	485
1997	1831	1419	654	1605	1146	457
1998	1968	1433	642	1617	1136	429
1999	2003	1451	631	1629	1134	389
2000	2037	1467	619	1638	1129	370

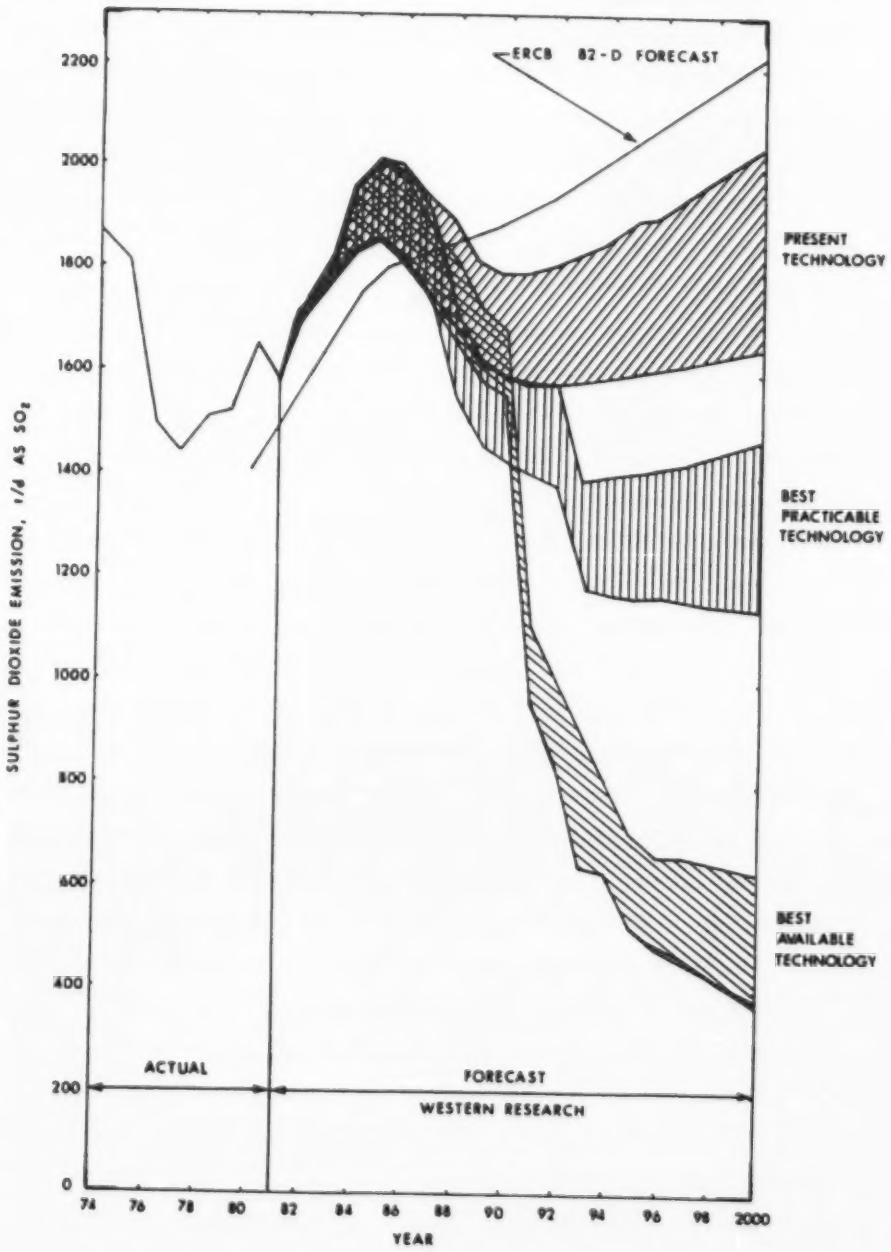

Figure 16. Sulphur dioxide emissions forecast 1980 - 2000.

Superimposed on Figure 16 is a recent forecast of sulphur dioxide emissions presented in ERCB 82-D, Sour Gas Processing in Alberta. This forecast is significantly higher than the present forecast after the 1988 time frame. Examination of their forecast indicates total emissions from oil sands plants to increase from 600 to 850 t/d between 1990 and 2000. Comparable numbers for the present forecast are similar when present technology is applied.

In the case of sour gas plants, the Board predicts emission levels significantly higher than the present forecast. Some of the discrepancy would be accounted for by the choice of the production ratio of sulphur to marketable gas. If the present production ratio ($91t/10^6m^3$) is maintained throughout the forecast period, the forecasts would be in reasonable agreement.

The present forecast has also been compared to forecast emissions contained in a report prepared for Oil Sands Environmental Study Group by Meteorological and Environmental Planning Limited (MEP) (1982). The present estimates for existing plants are higher than those in the MEP report. The difference is in the assumed observed daily emission rate relative to the licenced level. The present study used 90 percent for uncontrolled emissions and 100 percent for controlled emissions (at reduced licenced rates due to the application of control technology). MEP used 70 percent and no emission control was assumed.

With these few comparisons the present forecast appears to be within the range of other recent forecasts. In addition, it discusses the consequences of various assumptions that were made in developing the forecast.

4.5.2 Sensitivity Analysis

In order to examine high- and low-side deviations from the expected development scenarios presented in Figure 16, each source of sulphur dioxide was examined to determine the worst and best case for sulphur dioxide emissions. The two categories contributing the most significantly to this analysis were natural gas and electric power.

No adjustments were made for the application of control technology, although it would also be reasonable to examine the sensitivity of the forecast in respect of the application of technology to recover sulphur or control sulphur dioxide emissions.

The worst case sulphur dioxide emissions forecast was developed with the following assumptions:

1. Natural Gas

   - highest marketable gas forecast (Scenario A)
   - maintaining the present high production ratio of sulphur to marketable gas;

2. Oil Sands

   - highest growth forecast (Scenario A);

3. Electric Power

   - highest growth forecast (Scenario A)
   - maximum use of coal as energy source;

4. All Others

   - highest growth forecast (Scenario A).

The minimum sulphur dioxide emissions forecast was developed by adopting the following assumptions:

1. Natural Gas

   - lowest marketable gas forecast (Scenario B)
   - declining production ratio of sulphur to marketable gas with high sulphur reserves deleted from the production inventory;

2. Oil Sands

   - lowest growth forecast (Scenario B);

3. Electric Power

   - lowest growth forecast (Scenario B)
   - minimum use of coal to supply energy. This allows for 2000 MW of non-thermal production capacity corresponding to an all-hydro source or a combination of hydro and Western Grid sourced capacity;

4. All Others

   - lowest growth forecast (Scenario B).

The results of this sensitivity analysis are presented in Figures 17, 18 and 19 for, respectively, the application of present technology, best practicable technology and best available technology.

This analysis points out the importance of the sulphur to marketable gas production ratio and the favourable impact of the non-thermal electric power capacity.

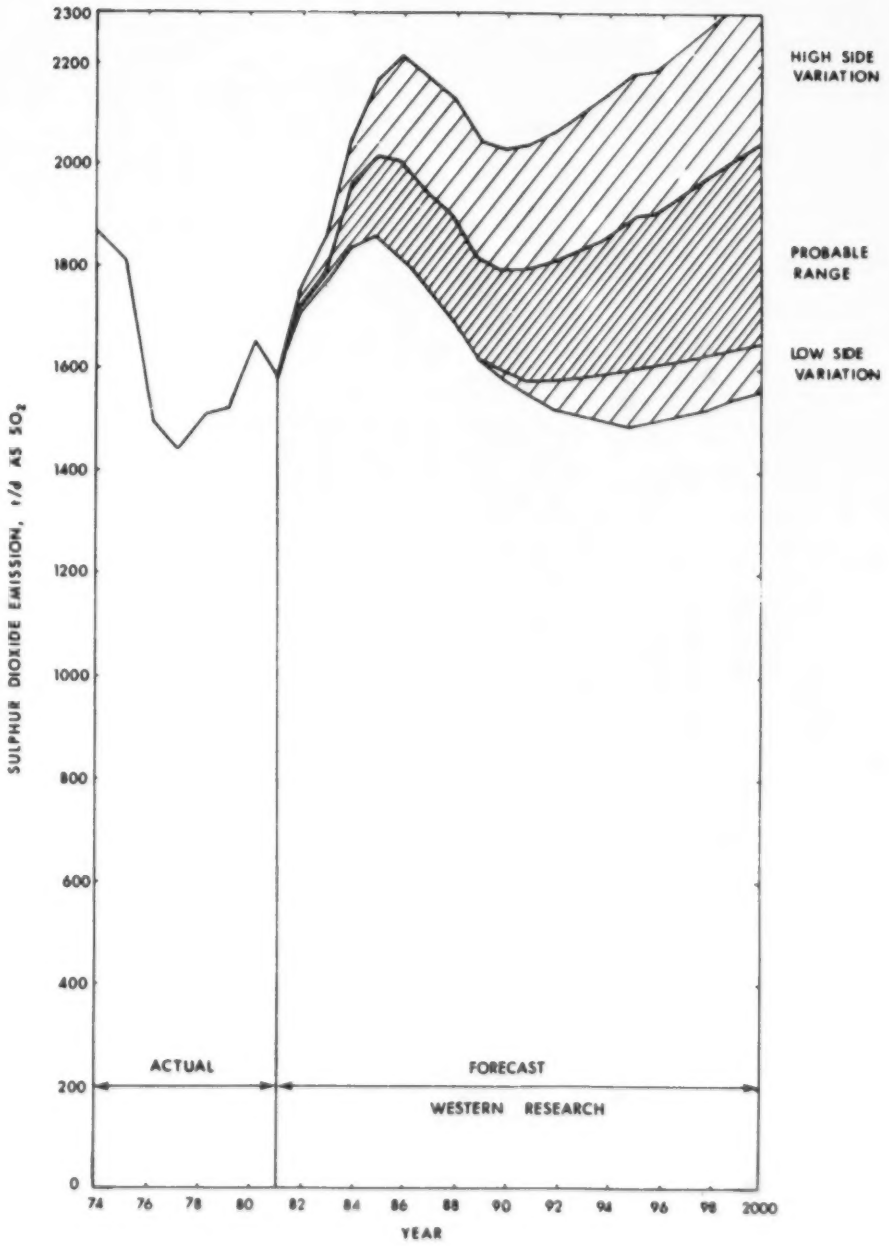

Figure 17. Sulphur dioxide emissions forecast 1980 - 2000: present technology - sensitivity analysis.

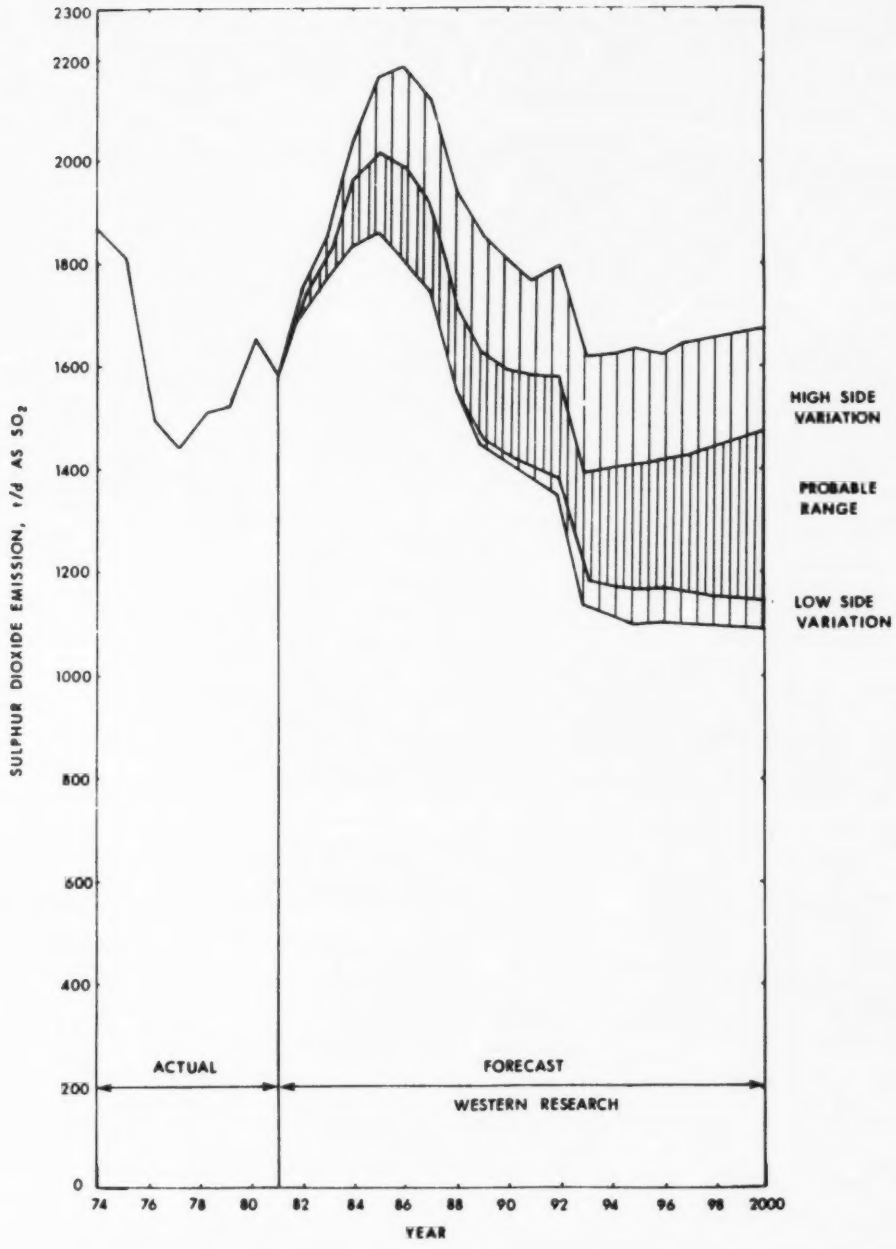

Figure 18. Sulphur dioxide emissions forecast 1980 - 2000: best practicable technology - sensitivity analysis.

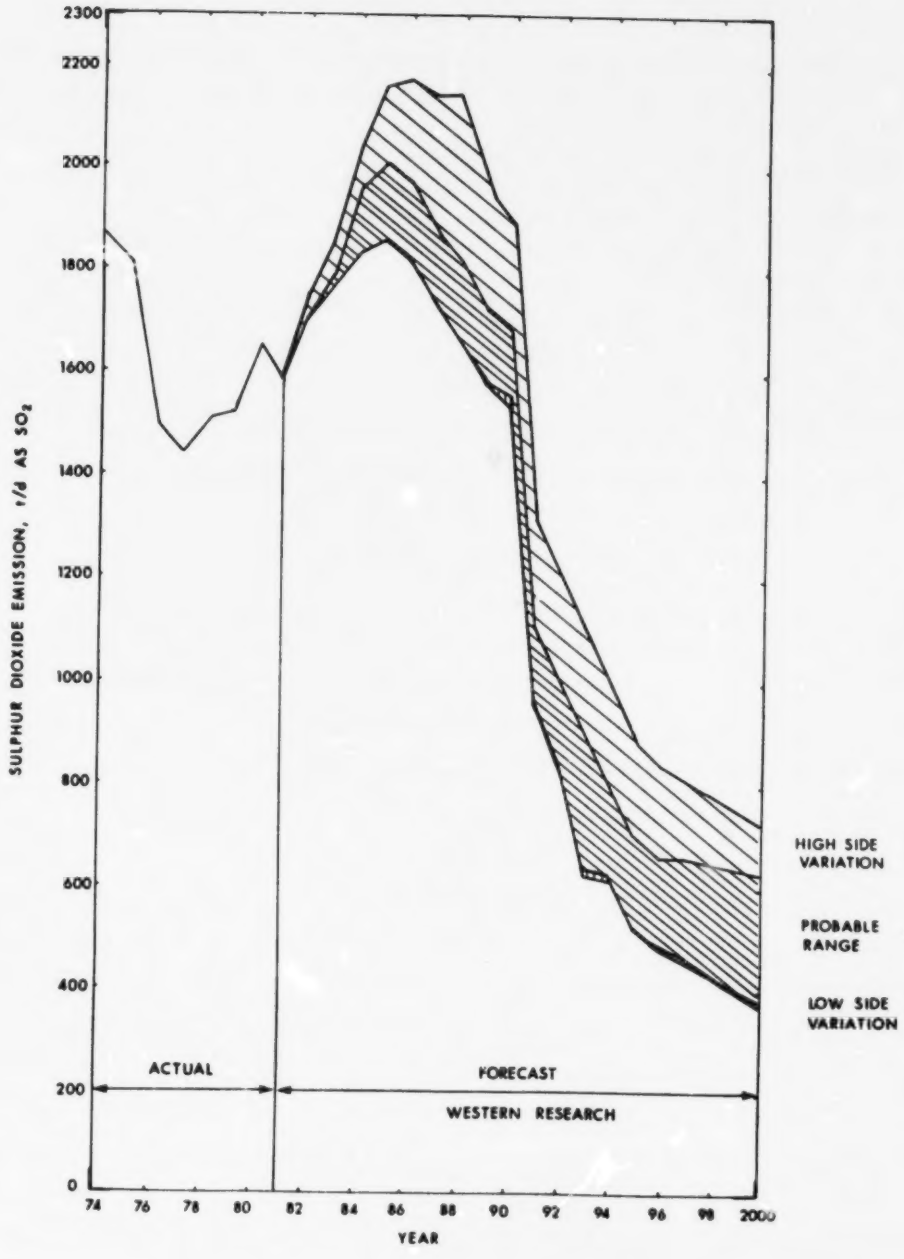

Figure 19. Sulphur dioxide emissions forecast 1980 - 2000: best available technology - sensitivity analysis.

5. CONCLUSIONS AND RECOMMENDATIONS

The forecast demonstrates that it is reasonable to assume that sulphur dioxide emissions in 2000 need not exceed those typical of the 1974 to 1981 time period. Application of best practicable technology to all industrial sectors will result in the achievement of this objective.

Applying best practicable technology will include:

1. Continuing efforts by industry to improve the efficiency of sulphur recovery at sour gas processing plants;
2. the application of flue-gas desulphurization technology or coal cleaning to future coal fired power plants;
3. the application of flue-gas desulphurization or alternative control technology to emissions at existing oil sands plants;
4. the assessment of modular oil sands plant sulphur emission levels to ensure compliance with the Alberta Environment guideline of 3.15 t/1000 m^3 of bitumen to upgrading.

Alberta sulphur dioxide emissions will be adversely affected if the present production ratio of sulphur to marketable gas is maintained or increased. Therefore, it is recommended that this subject be studied in more detail and, in particular, the production of very high sulphur sour gas should receive special consideration.

An adverse impact will also occur if future oil sands plants, regardless of size or scope, do not comply in principle with the Alberta Environment guideline for sulphur dioxide emission control.

The potential contribution by electric power industries to Alberta emissions will be significantly reduced by the proposed Slave River Hydro project, and may allow more cost-efficient sulphur

control systems to be applied to boilers in the 1990s than had previously been anticipated. Advances in combustion and sulphur control technology in the late 1980s should be closely monitored for this reason.

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7. APPENDIX A: EXCERPT FROM ALBERTA ENERGY RESOURCE REQUIREMENTS, 1981 TO 2005

Table 17. Alberta industrial profile, 1981 to 2005.[a]

Type of Project	Construction Period	Total Cost (1980 C $) Millions	Comment
1. Fertilizer	1981-1983	265	Sherritt Gordon
	1982-1984	305	Esso
	1987-1989	400	2200 t/d gas fed
	1991-1994	400	2200 t/d gas fed
	1997-2000	400	2200 t/d gas fed
2. Pulp and Paper	1984-1985	130	BCFP (TMP/news-print)
	1984-1986	160	TMP/paper
	1993-1995	130	TMP/newsprint
	1996-1999	415	Kraft
3. Pipeline	1980-1981	450	Pre-build
	1983-1985	1600	Foothills
	1983-1985	145	IPL/NWT
	1992-1995	825	Arctic oil
	1995-1998	2200	Arctic gas
4. Refinery	1981-1982	160	Gulf
	1981-1983	150	Imperial Oil
	1981-1983	140	Turbo
	1981-1984	540	Shell
	1990-1991	70	Shell expansion
	1990-1993	300	8.0 km^3/d
	1998-2001	400	12.0 km^3/d
5. Petrochemical	1980-1982	110	AGCL MeOH
	1981-1984	350	AGE II
	1981-1983	70	Dow - PE
	1981-1984	260	UCC - EO/EG
	1981-1982	230	Celanese - MeOH
	1981-1984	160	Styrene (Shell/Nova)
	1981-1984	210	Benzene (AEC/Esso)
	1981-1984	210	Styrene (AEC/Esso)
	1982-1985	350	AGE III
	1984-1986	220	VCM with Chlorine production
	1982-1987	510	4 x PE with plant start-up in 1984 (CIL), 1985, 1986 and 1987

continued...

Table 17. Continued.

Type of Project	Construction Period	Total Cost (1980 C $) Millions	Comment
	1986-1989	400	Ethylene with C_3/C_4 feedstock
	1987-1992	770	EO/EG-1990; Styrene - 1991 2 x PE-1991, 1992
	1986-1988	230	Methanol
	1989-1991	230	Methanol
	1994-1997	350	Ethylene with ethane feedstock
	1995-2000	930	EO/EG-1997; VCM-1998, 3 x PE in 1997, 1999, 2000
	2000-2003	350	Ethylene with ethane feedstock
	2000-2005	770	EO/EG-2003; Styrene -2004, 2 x PE-2004, 2005
6. Coal Mines			
(a) Thermal Export	1981-1983	120	Obed - Marsh
	1987-1989	120	
	1994-1996	120	
	2000-2002	120	
(b) Metallurgical	1981-1983	180	Gregg River
	1982-1984	180	Cardinal River
	1988-1990		
7. Export Power Project	1984-1992	1550	2000 MW
8. Oil Sands	1981-1987	5540	Alsands (M3)
	1981-1988	5140	Esso/Cold Lake (IS2)
	1985-1991	5540	Petro-Can/Nova (M4)
	1987-1994	5100	IS2
	1991-1997	5540	M5
	1993-2000	5100	IS3
	1996-2002	5540	M6
	1999-2005	4700	IS4 (prod'n in 2007)
	2002-2005	2190	M7 (prod'n in 2009)

continued...

Table 17. Concluded.

Type of Project	Construction Period	Total Cost (1980 C $) Millions	Comment
9. Oil Sands Expansion	1980-1981	175	Suncor
	1986-1989	2300	Syncrude
	1994-1997	2300	Alsands
	1999-2002	2300	Mining
10. Rail Electrification	1991-1996	510	Mainlines - CN, CP-
11. Agriculture	1996-2005	2500	Irrigation

[a] The source for this table is Electric Utility Planning Council, Western Natural Gas Company Ltd. and Northwestern Utilities Limited. 1981. 1981 Submission to the Energy Resources Conservation Board, Alberta Energy and Energy Resource Requirements 1981 to 2005. Calgary.

8. APPENDIX B: ELECTRIC UTILITY GROWTH

Indirectly, all industrial developments result in potential sulphur dioxide emissions through their requirements for electric power, the majority of which is supplied by coal-fired power plants. In the analysis of electric utility growth all industries are considered.

Alberta's electric power requirements from 1981 to 2005 were outlined in a submission to the Energy Resources Conservation Board dated January 1981 by the Electric Utility Planning Council, Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited. The report addressed the electrical energy and natural gas energy requirements of all sectors of the Alberta economy.

Table 18 outlines the 1980 and 2000 forecast growth and distribution of electric power requirements of the Alberta Interconnected System (AIS) by sector as presented in the EUPC submission. Over the twenty-year period a 3.2-fold increase was projected. The 1981 EUPC submission was used as a base to prepare the present forecast of electric utility growth.

The industrial development scenarios described in sections 3.1 to 3.4 of the report, as well as other related factors, were used to establish the present electric utility energy requirement forecast. The following sections outline the development of the present growth forecasts and, unless otherwise noted, the EUPC submission is adapted for Scenario A.

8.1 POPULATION

Current population figures for year-end 1981 are in line with the growth rates indicated in the EUPC submission. However, recent changes in the economic climate in Alberta may result in the actual growth being somewhat less than that predicted. Population projections by Alberta Treasury, Bureau of Statistics, in 1979, and updated in 1981, outline various growth scenarios. The medium fertility, low migration scenario (series 6) predicts a year 2000 population of 3 044 600. If this were to be the actual case, the

Table 18. AIS energy requirements.[a]

	1980 GW h	2000 GW h
Residential[b]	4 300	10 793
Commercial	6 655	15 600
Street Lighting	283	478
Farm	1 098	2 325
Transportation	595	5 564
Industrial		
oilfields	1 305	4 387
gas plants	940	2 921
natural gas reprocessing	268	1 557
refineries	374	1 132
oil sands	98	5 606
petrochemicals	1 571	4 192
forest products	147	1 625
cement	168	769
coal	425	2 235
other industrial	1 445	3 491
Total AIS Industrial	6 691	28 515
Losses	2 139	6 644
Alberta Total	21 761	69 919

[a] Source - Canada. National Energy Board. 1981. Canadian energy supply and demand 1980-2000.

[b] present population 1980 - 2 132 000
projected population 2000 - 3 802 000

impact on residential energy requirements would be approximately 20 percent and the resultant electrical energy requirement would be reduced to about 8644 GW h for year 2000. For Scenario B this was assumed reasonable and requirements over the forecast period are summarized in Table 19.

8.2 COMMERCIAL

Assuming that commercial growth parallels population increases, the impact of a reduced year 2000 population would be about 3108 GW h, resulting in a revised demand of about 12 494 GW h for Scenario B. Requirements are summarized in Table 19.

8.3 STREET LIGHTING

This component is proportional to population and for Scenario B the reduced demand would be 383 GW h by 2000. Requirements are summarized in Table 19.

8.4 FARM

No changes are anticipated in the demand forecast for farm requirements for electric energy. The forecast is based on historical usage and projected growth, and on a separate analysis of irrigation requirements. Requirements are summarized in Table 19.

8.5 TRANSPORTATION

This category includes crude oil and natural gas pipelines, interbasin water transfer and rail line electrification requirements. The requirements have been re-estimated using the present oil production estimates and discussions with EUPC representatives (Taylor: pers. comm.). For Scenario A, electrification requirements for main rail lines come into play in 1995; for Scenario B no electrification is assumed until after year 2000. Requirements are summarized in Table 19.

Table 19. Electric energy requirements (residential, commercial, street lighting, farm and transportation).[a]

	Scenario	Year 1980	1985	1990	1995	2000
Population (thousands)	A	2 132	2 536	2 960	3 372	3 802
	B	2 079	2 355	2 602	2 830	3 045
Sector		Electric Energy Requirements GW h				
Residential	A	4 300	5 925	7 481	9 101	10 793
	B	4 300	5 502	6 576	7 638	8 644
Commercial	A	6 655	8 437	10 250	12 605	15 600
	B	6 655	7 835	9 010	10 646	12 494
Street Lighting	A	283	340	366	380	478
	B	283	316	322	319	383
Farm	A	1 098	1 392	1 632	1 842	2 325
	B	1 098	1 392	1 632	1 842	2 325
Transportation	A	484	880	904	1 171	2 261
	B	484	880	904	850	867
Total	A	12 820	16 974	20 633	25 179	31 457
	B	12 820	15 925	18 444	21 295	24 713

[a] Source: Scenario A - EUPC Submission 1981
Scenario B - Western Research estimates except population
Scenario B - Population - Bureau of Statistics 1981

8.6 INDUSTRIAL

This component is complex and is subdivided into categories for review and adjustment.

8.6.1 Oilfield

Electric energy demand in conventional oilfield operations is expected to proceed as predicted by EUPC 1981. The requirements are listed in Table 20.

8.6.2 Gas Plants

Gas plant electric energy requirements have been estimated using Case 1 and Case 4 forecasts of Alberta marketable gas delivery from Table 4 Section 3.1. Estimates have not been made using the two intermediate marketable gas delivery forecasts (Cases 2 and 3). The range from Case 1 to Case 4 (lowest to highest) is about 25 percent.

The electric energy requirements for natural gas production were previously estimated to range from about 12 to 14 GW h/$10^9 m^3$ over the forecast period (EUPC 1981). For the present forecast, a value of 14 GW h/$10^9 m^3$ was used for the entire period.

In addition, major drive compression requirements were estimated using the revised gas deliveries and the EUPC data.

The results are shown in Table 20.

8.6.3 Natural Gas Reprocessing

The demand for electric energy is expected to remain as forecast for Scenario A, but for Scenario B the requirements are adjusted in the years 1983 to 1988 to reflect the current shift in ethylene production facilities. The electric energy requirements for Scenario A and B are listed in Table 20.

8.6.4 Refineries

Refinery requirements for electric energy for the two growth scenarios described in Section 3.4.3 of the report are outlined in Table 20 and are based on revisions to the EUPC submission.

Table 20. Electric energy requirements (industrial).

Sector	Scenario	Year 1980	1985	1990	1995	2000
		Electric Energy Requirements GW h				
Oil Fields	A	1 305	2 230	3 184	3 795	4 387
	B	1 305	2 230	3 184	3 795	4 387
Gas Plants	A	991	1 908	2 040	2 480	3 042
	B	991	1 605	1 589	1 904	2 490
Natural Gas Reprocessing	A	268	1 254	1 557	1 557	1 557
	B	268	592	1 557	1 557	1 557
Refineries	A	374	827	864	1 066	1 066
	B	374	827	827	972	972
Oil Sands	A	98	500	759	2 109	2 891
	B	98	400	600	800	1 000
Petrochemical	A	1 571	2 923	3 420	3 733	4 418
	B	1 571	2 923	3 420	3 733	4 418
Forest Products	A	140	445	1 122	1 253	1 625
	B	140	195	449	1 130	1 132
Cement	A	168	410	511	630	769
	B	168	410	511	630	769
Coal	A	425	864	1 210	1 601	2 073
	B	425	817	1 132	1 455	1 816
Other	A	1 445	1 845	2 197	3 118	3 672
	B	1 445	1 845	2 197	3 118	3 672
Total	A	6 785	13 206	16 864	21 343	25 500
	B	6 785	11 844	15 460	19 094	22 213

8.6.5 Oil Sands

The electric energy demand of oil sands projects has been estimated based on projected production rates presented in Table 4. AIS requirements, as developed in the EUPC submission, were revised based only on the revised production rates. No allowance was made for a greater or lesser amount of on-site electric energy supply.

The revised estimates for Scenarios A and B are summarized in Table 20.

8.6.6 Petrochemical

The developing petrochemical industry has been discussed (Section 3.1) and, taking these factors into consideration, the growth to year 2000 is forecast to be about 15 percent less than that forecast by the EUPC. This estimate is based on a 3 year lag in achieving the previously anticipated level of development. Only one growth scenario was developed and the resultant electric energy requirement is outlined in Table 20.

8.6.7 Forest Products

The forest products group includes milling operations and pulp and paper plants.

Using the two scenarios developed earlier (Section 3.3) for pulp and paper plants and assuming no change in EUPC submission estimates for milling, the revised estimates listed in Table 20 have been developed.

8.6.8 Cement

No changes in the EUPC growth forecasts were assumed, although there could be a significant decrease in the demand for cement if the Alberta population were 3.0 million rather than the 3.8 million by the year 2000. However, the impact of a small change in the cement industry's electric energy needs would have a minimal impact on the total AIS demand.

The EUPC estimates are listed in Table 20.

8.6.9 Coal

The EUPC energy demand forecast for mining of metallurgical, thermal, export and industrial coal was not adjusted. The electrical energy requirements for mining AIS coal were adjusted to reflect the reduced demand for AIS coal.

The requirements are listed in Table 20.

8.6.10 Other Industrial

Although this demand is significant, the EUPC forecast has not been adjusted for the present forecast. The requirements are listed in Table 20.

8.7 LOSSES

Losses are estimated at 11 percent of total demand for the entire forecast period and are listed in Table 21.

8.8 SUMMARY

Table 21 summarizes the total AIS electrical energy requirements as revised for Scenarios A and B over the forecast period. Figure 20 compares the 1981 EUPC estimates with the present revised estimates. By 2000 Scenario A and Scenario B forecasts are, respectively, 10 and 25 percent less than the 1981 EUPC forecast.

8.9 COAL-SUPPLIED ELECTRIC ENERGY

The electric energy supplied by coal for the present forecast is calculated using the same assumptions for grid and hydro sources of electric energy, as outlined in Case 1 and Case 3 of the EUPC submission. Case 1 assumes a maximum contribution by coal while Case 3 assumes that 2000 MW of non-thermal capacity is brought on stream between 1990 and 1995. Although the data presented corresponds to this capacity being sourced by the Western Grid (1000 MW) and an unspecified hydro project (1000 MW), it is most likely that the recently announced Slave River Hydro project will supply the total capacity.

The results are summarized in Table 22 and Figure 21.

Table 21. Total AIS electric energy requirements (GW h).

	1980	1985	1990	1995	2000
Scenario A					
Non Industrial (Table 7)	12 820	16 974	20 633	25 179	31 457
Industrial (Table 8)	6 785	13 206	16 864	21 343	25 500
Losses at 11%	2 157	3 320	4 125	5 117	6 265
Total Estimate	21 762	33 500	41 622	51 639	63 222
Scenario B					
Non Industrial (Table 7)	12 820	15 925	18 444	21 295	24 713
Industrial (Table 8)	6 785	11 844	15 466	19 094	22 213
Losses at 11%	1 410	3 055	3 730	4 443	5 162
Total Estimate	21 762	30 824	37 640	44 832	52 088

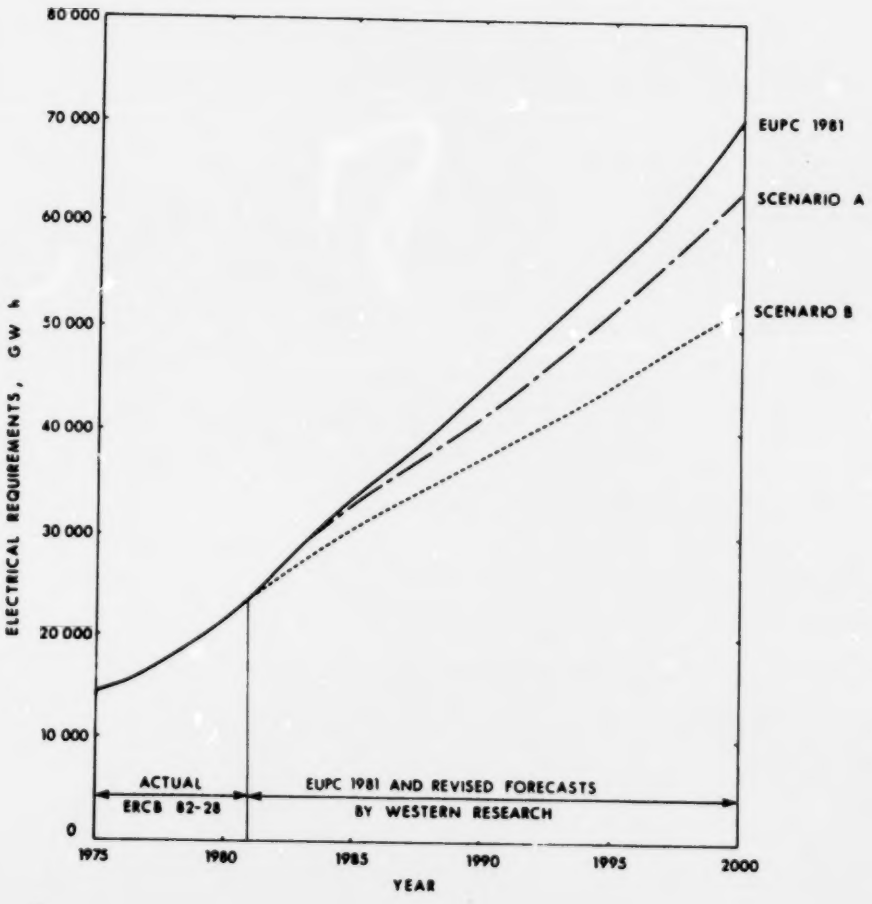

Figure 20. Total AIS electrical requirements.

Table 22. Supply of energy requirements by source type (GW h).

	Hydro	Gas	Grid	Revised Total[a]	Coal Portion
Scenario A					
Case 1 - All Coal					
1980 (Actual)	1 699	3 728	0	21 762	16 335
1985	1 780	4 380	6	33 500	27 334
1990	1 780	3 724	10	41 622	36 108
1995	1 401	3 547	36	51 639	46 655
2000	1 330	3 833	49	63 222	58 010
Case 2 - Hydro Plus Western Grid					
1980 (Actual)	1 699	3 728	0	21 762	16 335
1985	1 780	4 380	6	33 500	27 334
1990	1 780	4 181	50	41 622	35 611
1995	5 715	3 760	4 421	51 639	37 743
2000	5 644	2 364	4 386	63 222	50 828
Scenario B					
Case 1 - All Coal					
1980 (actual)	1 699	3 728	0	21 762	16 335
1985	1 780	4 380	6	30 824	24 658
1990	1 780	3 724	10	37 640	32 126
1995	1 401	3 547	36	44 832	39 848
2000	1 330	3 833	49	52 088	46 876
Case 2 - Hydro Plus Western Grid					
1980 (actual)	1 699	3 728	0	21 762	16 335
1985	1 780	4 380	6	30 824	24 658
1990	1 780	4 181	50	37 640	31 629
1995	5 715	3 760	4 421	44 832	30 936
2000	5 644	2 364	4 386	52 088	39 694

[a] Actual total for 1980 is 21 910. Table 22 estimated total for 1980 is 21 361

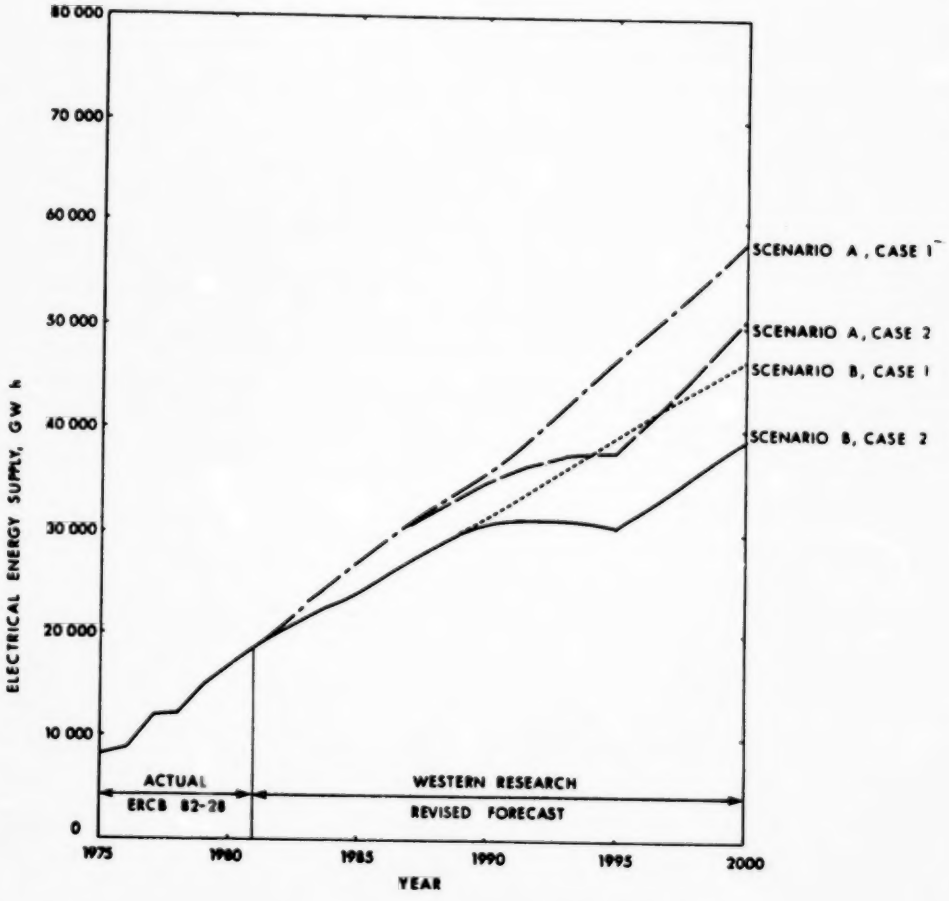

Figure 21. AIS electrical requirements supplied by coal.